

CALIFORNIA ENERGY RESOURCES CONSERVATION  
AND DEVELOPMENT COMMISSION  
INTEGRATED ENERGY POLICY REPORT COMMITTEE

WORKSHOP  
AGING POWER PLANT STUDY

CALIFORNIA ENERGY COMMISSION  
HEARING ROOM A  
1516 NINTH STREET  
SACRAMENTO, CALIFORNIA

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PETERS SHORTHAND REPORTING CORPORATION (916) 362-2345

COMMITTEE MEMBERS PRESENT

John L. Geesman, Chairperson

Jackalyne Pfannenstiel

Melissa Jones, Commissioner Advisor

Michael Smith, Commissioner Advisor

STAFF PRESENT

Matt Trask, Project Manager

Eileen Allen

Sandra Fromm

David Vidaver

Matthew Layton

Mark Hesters

Caroline Jackman

Dale Edwards

Rick York

Noel Davis, Chambers Group  
Consultant

ALSO PRESENT

Philip Pettingill

Catalin Micsa

Mary Jo Thomas

California Independent System Operator

Vitaly Lee

Steve Maghy

AES Pacific, Inc.

Tim Hemig

NRG Energy, Inc.

Al Wang

Environmental Health Coalition

ALSO PRESENT - continued

Katie Kaplan  
Independent Energy Producers

Trent Carlson  
Reliant Energy

Gary Schoonyan  
Southern California Edison

Kevin Loscutoff  
Mark Osterholt  
Mirant California, LLC

Scott Peterson  
SDGE

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## I N D E X

	Page
Proceedings	1
Opening Remarks	1
Staff Presentations	
Status to Date	
Matt Trask, Project Manager	2
Role of Aging Plants in the System	
Dave Vidaver	12
Air Emissions and Aging Power Plants	48
Land Use Issues	
Eileen Allen	60
Biological Analyses	
Noel Davis	63
Environmental Justice	
Dale Edwards	71
Next Steps	
Matt Trask, Project Manager	73
Catalin Micsa, Grid Planner	
Independent System Operator	77
Lunch Break	97
Afternoon Session	98
Public Comment, Other Presentations	
Vitaly Lee	
AES Pacific, Inc.	98
Panel Discussions	
Panel 1 - Environmental and public health effects of aging plant operation	105
Panel 2 - The APPS study list and the role aging power plants play in the system	143

## I N D E X

	Page
Other Presentations	
Trent Carlson Reliant Energy	162
Panel Discussions - continued	
Panel 3 - Present and anticipated plans, policies, and projects that could affect aging plant economics	186
Panel 4 - Reliability effects of plant retirements	219
Adjournment	246
Certificate of Reporter	247
Reporter's Certificate	

## P R O C E E D I N G S

CHAIRPERSON GEESMAN: Why don't we go ahead and get started.

This is another in our continuing series of workshops on the role that our so-called aging power plant fleet plays in meeting the state's reliability needs. This is a bit of a replay of an earlier workshop that we're holding again to provide for broader participation. I think that the last time we had this topic in front of us there was an unanticipated conflict with several other proceedings, so many of you were not able to, to attend. We wanted to make certain that we did have the benefit of a broader range of input before moving forward.

The primary task of the workshop process is to attempt to take the subject area out of the rhetorical and into the empirical, and one of the, one of the aspects of that is to, to make certain that we're all using terms in the same fashion. The staff has heard this from me sufficiently, frequently, of late, that I think we're getting closer to being on the same wavelength, and hopefully over time we can get all of the parties in the same position so that we better understand

1       what we mean when we use certain phrases.

2               I'd also like to get a better sense of  
3       how well calibrated the various stakeholders feel  
4       that our analytic tools are. What we envision  
5       ultimately doing is, is providing, first, a staff  
6       white paper, then a committee report. Ultimately,  
7       a set of recommendations adopted by the full  
8       Commission by the end of October that can provide  
9       some illumination on the question of the role of  
10      these aging plants.

11              With that, Commissioner Pfannenstiel,  
12      did you have anything to say?

13              COMMISSIONER PFANNENSTIEL: No, thank  
14      you. I am really just here to listen and learn.

15              CHAIRPERSON GEESMAN: Mr. Trask.

16              MR. TRASK: Thank you, Commissioner.

17              Hi, I'm Matt Trask, I'm the Project  
18      Manager for the Aging Power Plant Study, and I  
19      have a few sort of housekeeping announcements  
20      here.

21              Well, first I'll go over a little bit of  
22      the agenda, if you haven't picked one of those up.  
23      We are going to have series of staff presentations  
24      by myself and a few other people, basically on  
25      what we've been learning to date. Then we'll have

1 a period right after that where we will allow  
2 other presentations. I know we have Catalin  
3 Micsa, of the ISO, is here to do a short  
4 presentation on their RMR process. We'll do that  
5 right after the staff presentations, probably  
6 right around 11:30. Then we'll break for lunch,  
7 and also we'll have an opportunity there for  
8 comment for virtually anybody who wants to get up  
9 and talk.

10 Then we'll break for lunch, and we'll  
11 come back and we'll have a series of panel  
12 discussions where we'll rearrange a little bit  
13 here in the middle, and we'll get it to where we  
14 can have more of an exchange, and those are also  
15 announced in the agenda, the topics of the, of the  
16 panel discussions. We're going to start with the  
17 environmental panel discussion. That one was not  
18 held the last workshop and we have some people  
19 with travel schedules that need to get going in  
20 the afternoon. So we'll do the environmental  
21 discussion first.

22 Wanted to let you know this is part of  
23 the 2004 update to the 2003 Integrated Energy  
24 Policy Report, IEPR. The Aging Power Plant Study  
25 is one of three main components of that update,

1 the other two being on renewables and on  
2 transmission policy. The rough schedule is to  
3 produce a draft study in July. We'll have  
4 workshops on the study in August, and the final  
5 document will be released in September, hearings  
6 and adoption in October, and transmit to the  
7 Governor in November.

8 We encourage people to participate in  
9 the panel discussions this afternoon, as well as  
10 to provide comment throughout the workshop. If  
11 you have a point to make or a question to ask,  
12 please feel free to, to do so. We ask that you  
13 fill out a blue card if you want to speak.  
14 They're out here on the, on the table out in  
15 front, and give it to myself or to Caroline  
16 Jackman, here. And then we'll arrange so that you  
17 can come up and speak.

18 Similarly, if you want to participate in  
19 the panel discussion this afternoon, please let me  
20 know and we'll make a spot for you.

21 For those of you listening in on the  
22 web, trying something a little bit new this time.  
23 If you would like to participate in the panel  
24 discussions I'm asking that you give my office  
25 number a call, 916/654-4067, and I'll repeat that

1 later on, and just give me your name and number  
2 and we'll bring you in by conference phone. We do  
3 have one party that I know of that will do that  
4 during the environmental.

5 We do have restrooms out behind us here.  
6 There's a snack bar up on the second floor where  
7 you can get sandwiches and drinks, and so forth.  
8 And the last thing I want to do is ask that you  
9 turn off your cell phone or put it on a silent  
10 mode.

11 With that, I'm going to go right into  
12 our presentations. Get the light set up here.  
13 Can everybody see fine here? Let's start just  
14 with the status to date, what we've learned, and  
15 where we need to go from here.

16 We've had two workshops before. As  
17 Commissioner Geesman mentioned this workshop is  
18 essentially a repeat of a workshop we had on May  
19 18th, where there were some scheduling conflicts  
20 for various people and they could not make it, so  
21 we're, we're repeating this workshop. During that  
22 workshop we explained that the, the study has  
23 essentially three objectives. We're looking at  
24 the role of the aging power plants both in system  
25 reliability and the local reliability, two of

1       those terms that we'll, we'll define well in our  
2       study. We're also looking at the environmental  
3       and natural gas implications of both retirements  
4       of these aging plants and the continued reliance  
5       on them. And then we're going to analyze a very  
6       wide range of possible retirements and, and try to  
7       predict what the implications of those retirements  
8       are.

9               As I said before, this is part of the  
10       2004 Update to the IEPR. We selected 66 units to  
11       study. These were units that are built before  
12       1980. They're all natural gas fired, and they are  
13       non-peakers. We decided not to look at non-  
14       peakers to the same depth as these larger units  
15       for several reasons. One is that they are  
16       designed only to run during a few hours per year,  
17       during the, what we call the super peaks, or  
18       generally during the hot summer months. And  
19       they're all generally a lot smaller than these  
20       aging units.

21              So we feel we have a fairly good  
22       sampling of, of these aging units, and can use  
23       them as our study group to assess the implications  
24       of, of retirement.

25              We have been talking with quite a few

1 parties. We've had several interviews and one-on-  
2 one meetings with the California Independent  
3 System Operator, whom we feel is a very crucial  
4 partner in this study, but also with several of  
5 the merchant plant owners, a few of the investor  
6 owners -- investor-owned utilities, and as well as  
7 the municipal utilities.

8 We are gathering information from also  
9 those same parties, as well as some of the  
10 regulatory agencies that are also involved in  
11 energy regulation, the Federal Energy Regulatory  
12 Commission, the California Public Utility  
13 Commission, and the North American Electric  
14 Reliability Council being among those.

15 As I mentioned before, when we selected  
16 out 66 units we, of course, they had to be grid  
17 connected, fueled by natural gas, built before  
18 1980, and larger than ten megawatts. We already  
19 knew some that were scheduled to retire before  
20 2005, so we eliminated those as well as the  
21 peakers.

22 And this is what we ended up with. The  
23 red circles are the, I think 24 power plants, 66  
24 units or 24 power plants, all of them built before  
25 1980. As you can see, most of them are in

1 southern California, and that's where quite a bit  
2 of our analysis is going to, to be focused.

3 And with that, I'm going to turn it over  
4 to Dave Vidaver, who's -- oh, no, I'm not. I've  
5 got one more here.

6 In our meetings to date, these are some  
7 of the comments we've received. These are  
8 generally from the generators themselves, the  
9 merchant plant owners. They are all unified,  
10 every single one of them has said that there is  
11 definite need for a change to the market  
12 structures and the Must-Offer requirement if they  
13 are to stay in business.

14 We've also heard from both the merchant  
15 owners and the municipal owners that these aging  
16 power plants require quite a bit of maintenance  
17 spending in order to be able to participate in  
18 markets, and this is kind of a conundrum for many  
19 of the owners. You have to spend a lot just to be  
20 able to participate, but you have no idea how much  
21 you're going to be able to participate. So it's  
22 a, definitely a gamble.

23 Other comments we've seen are that  
24 retirements are very highly possible, but a lot of  
25 people are sort of holding on, hoping that the

1 other guy will retire, because that would improve  
2 the economics for those who stay in the, in the  
3 market.

4 Also heard from many parties that aging  
5 power plants do definitely provide very valuable  
6 services, especially to local reliability. These  
7 are other services besides just capacity. They  
8 could be cold start -- excuse me, black start  
9 capability, ability to support, frequency support,  
10 those kind of things.

11 Most people have told us, especially on  
12 the generator side, that the impacts of the aging  
13 plants are insignificant. This is, of course, a  
14 controversial issue, and we're analyzing that to  
15 some depth. But that's based largely on the fact  
16 that they don't operate all that much, and that  
17 they are generally been upgraded to the most  
18 recent standards for air quality and other  
19 environmental standards.

20 Another common theme that we've heard  
21 from all the generators, the munis and the, the  
22 merchant owners, is that these plants are not  
23 operated the way they were designed. All these  
24 plants were operated as baseload plants, where  
25 they would start up, get up to close to maximum

1 power, and stay there, night and day. Since these  
2 plants were built, obviously many things happened.  
3 Nuclear plants were built, combined cycle plants  
4 were built, those generally can supply baseload  
5 power either cheaper or, in the nuclear plants,  
6 they have no choice, they just can't ramp up and  
7 ramp down as fast.

8 So in effect, these plants have shifted  
9 to a deep cycle mode. They start off very low  
10 powers in the morning and then build up, ramp up  
11 during the day towards the peak in the afternoon,  
12 and then ramp down into the evening. Now, this  
13 has caused additional mechanical stress on the,  
14 especially the metallurgy and the turbines, and so  
15 forth, and this is one of the reasons why these  
16 aging plants have such high maintenance costs.

17 Some of the aging plants definitely want  
18 to compete for peaking capacity needs. Right now  
19 it's about the only solicitations out there are  
20 for peaking needs, and some of these plant owners  
21 have told us that they will meet or beat any  
22 peaking plant contract price.

23 Another universal theme is that the same  
24 market uncertainty that may cause these  
25 retirements is also preventing new plant

1 construction. And that's kind of a vicious cycle  
2 there. As aging plants retire, leaving fewer and  
3 fewer plants to, to meet load, there's also no  
4 incentive to building plants to replace them.

5 One theme from the ISO that they've,  
6 they've expressed a desire for is additional  
7 noticing requirements for these plant retirements,  
8 or the mothballing. Apparently they have found  
9 out a few times after the fact, that an owner  
10 would say oh, we retired that unit about three or  
11 four weeks ago.

12 And lastly, what we've heard from a  
13 couple of the generators, an interesting  
14 assertion, anyway, is that the efficiencies of  
15 these aging plants are actually fairly close to  
16 new plants, new combined cycle plants, when they  
17 are cycled the way they are, when they start off  
18 low power, go to high power, and then back down.  
19 If you looked at the aggregate heat rate of a  
20 combined cycle plant compared to a, a boiler unit,  
21 according to some of these generators you would  
22 see that they're not all that much different.  
23 That's something that we haven't verified yet, but  
24 we find it quite interesting.

25 And with that, I'm going to turn it over

1 to Dave Vidaver to talk about the role these  
2 plants have played in the system.

3 MR. VIDAVER: Good morning. This is  
4 essentially a repeat of a presentation I gave a  
5 couple of weeks ago, so if you were here two weeks  
6 ago, you can simply lie back and think of England,  
7 or something. The only difference is I'm wearing  
8 a tie, which is cutting off the oxygen to my  
9 brain.

10 As Matt said, there are 24 power plants,  
11 24 power plants, 66 units under study. This is  
12 yet another graphical representation of them. You  
13 can see that most of them are located in SP 15.  
14 Not all of the units at the 24 locations are under  
15 study. Only, let's see, Humboldt, Contra Costa 6,  
16 Pittsburg 7, Potrero 3, Hunter's Point 4, Morro  
17 Bay and Moss Landing lie outside of SP 15. So the  
18 increasing tightness of supply and demand in SP 15  
19 is further threatened by the possibility that  
20 aging power plants are going to retire.

21 We've eliminated from the study of the  
22 economics of retirement the medium plants in the  
23 set. They're going to continue to be studied with  
24 respect to their environmental footprint and the  
25 implications of their continued operation and

1       their retirement. With the exception of Hunter's  
2       Point 4, we expect these plants to stay online for  
3       the indefinite future. We're hoping that Hunter's  
4       Point 4 will retire, Jefferson Martin gets  
5       completed. Everybody in the state wants to see it  
6       retired.

7               The remaining plants, two units at  
8       Grayson, Scattergood and Olive, Haynes, Broadway  
9       and a unit at El Centro, are likely to remain in  
10      service for a number of reasons. One, munis have  
11      already either retired or retrofit for emissions  
12      the plants that they were required to make  
13      decisions on. For example, under Rule 2009 in the  
14      South Coast, so we, we don't expect to see  
15      anymore, we certainly won't see anymore  
16      retirements in the near future due to the need for  
17      extensive capital outlays for emission retrofits.  
18      The munis have guaranteed cost recovery. They can  
19      compel recovery and rates, so there's very little  
20      risk in that regard.

21             The tightening that we see in the over  
22      the counter forward markets, especially south of  
23      Path 15, is such that munis in southern California  
24      would seem to be very apprehensive about the  
25      possibility of spot market exposure over the next

1 couple of year. We see this in the permits that  
2 come before the Commission, decisions to build  
3 such plants as Magnolia, Pico, and San Jose, the  
4 recent permit request that we have received from  
5 Riverside. So they've, the likelihood that spot  
6 market prices may, may remain high for the next  
7 couple of years, especially during the summer, is  
8 going to compel, we feel, munis to keep existing  
9 older plants online.

10 The, the total amount of capacity that  
11 we're talking about here is in the neighborhood  
12 about 17,000 megawatts. Munis, the muni plants  
13 that we feel will stay online, about 2300  
14 megawatts of that, so.

15 This graph shows the operation in  
16 aggregate of the 13,700 megawatts of capacity.  
17 It's the original 17,000 megawatts less the muni  
18 plants, less I think it's 600-plus megawatts for  
19 two units at Long Beach. The data we have, the  
20 generation data we have for those two units is  
21 really shaky, so we didn't want to include it in  
22 our numeric analysis. So we have 13,700 megawatts  
23 of capacity here, and this is, these are typical  
24 weeks for each quarter of 2003.

25 There are 168 hours in each week. We

1 began very early on Sunday morning, and continued  
2 through the week until Saturday evening. And what  
3 this shows is that we rely on these plants more in  
4 the summer than we do during any other time of the  
5 year, that we actually got to an instantaneous  
6 capacity factor during the average summer weekday  
7 peak of somewhere in the neighborhood of, looks  
8 close to 50 percent. The relative position of, of  
9 the lines in the remaining three quarters is sort  
10 of accidental. It will vary from year to year,  
11 depending on hydrology. The, the numbers for 2002  
12 are such that the, the lower three lines are  
13 shortly rearranged. So we, we rely on these  
14 plants to provide energy during summer peaks.

15 Now, one might come to the conclusion  
16 that a 50 percent capacity factor for this group  
17 of plants during weekday peaks, during the summer,  
18 is, indicates that we have some surplus. However,  
19 the previous graph, which is duplicated here, the  
20 blue line shows the typical summer week output for  
21 this set of plants. During high temperature weeks  
22 during the summer, these values can get  
23 substantially higher. You can see that in this  
24 particular week on Monday, this set of plants was  
25 producing more than 10,000 megawatt hours of

1 electricity at the time of the, the peak.

2 The, even this number is slightly low.

3 The hottest day in 2003 wasn't very hot, by  
4 historical standards. We actually had the coolest  
5 hottest day in 54 years, in at least 54 years. We  
6 only have 54 years of data. So in a typical  
7 summer that red line would actually be higher in  
8 2002. The, the peaks topped out at over 11,000  
9 megawatts from this set of plants.

10 And correspondingly, the, the blue line,  
11 which represents average temperatures during the  
12 summer, is actually in this graph higher than it  
13 would've been under normal temperature conditions.  
14 Despite the fact that it never got really, really  
15 hot last summer, on average it was very, very hot.  
16 It was the third or fourth hottest summer that  
17 we've experienced since 1950.

18 CHAIRPERSON GEESMAN: Dave, these lines  
19 represent the average of your study group, with,  
20 with the adjustments that you described before?

21 MR. VIDAVER: The, the blue line  
22 represents the, the average over the course of the  
23 entire summer. The red line indicates the actual  
24 generation during the week in which the ISO peak  
25 occurred in 2003.

1           CHAIRPERSON GEESMAN: If you isolated  
2     the SP 15 plants, would the, the difference be  
3     more stark?

4           MR. VIDAVER: I, yeah, I'm certain it  
5     would be. Yeah, most of these plants lie in SP  
6     15. So it would also depend on the temperature  
7     conditions that prevailed at the time of the  
8     system peak. And peak temperatures, when the  
9     temperature spikes in southern California, that's  
10    when the ISO's most likely to experience its, its  
11    overall system peak.

12           So, yeah, the condition in SP 15 is, is  
13    much tighter than ISO control area like numbers  
14    would indicate. So.

15           Let's see. What else do we have here.  
16    Okay. One thing we've observed is a, a decreased  
17    reliance on these plants for energy from 2002  
18    through 2003. The blue line represents a typical  
19    operation of this set of plants collectively in  
20    2002, during Quarter 1. In 2003, the output of  
21    these units dropped by 37 percent during this  
22    quarter. This will hold true for every single  
23    quarter of the year.

24           The 54 percent drop in generation in  
25    Quarter 2 of 2003, which only a small portion of

1       which can be explained by hydrology, a 28 percent  
2       drop in generation from these plants in Q3, and a  
3       30 percent drop in Q4, very little of this was due  
4       to hydrology. Most of it would seemingly be due  
5       to the fact that we've added a lot of new capacity  
6       between the summer of 2002 and the summer of 2003.  
7       We added La Paloma, High Desert, Elk Hills, and  
8       Sunrise, I believe.

9               One thing that this graph doesn't,  
10       doesn't reveal is that a disproportionate share of  
11       the drop in generation from 2002 to 2003 was  
12       incurred by non-RMR units. The ISO's need for  
13       energy from RMR units fell slightly from 2002 to  
14       2003, whereas those aging units that did not have  
15       RMR contracts suffered the biggest hits.

16              Projections for 2004. It appears as  
17       though we're going to be depending on these plants  
18       for energy to a greater extent in 2004, for a  
19       variety of reasons. One is we've added no major  
20       facilities in the state since December of 2003.  
21       We've had more than 1100 megawatts of capacity  
22       mothballed, but I understand that 640 megawatts of  
23       that might be coming out of mothballs. The ISO's  
24       here and can comment on that.

25              CHAIRPERSON GEESMAN: I take it you're

1 referring to Etiwanda?

2 MR. VIDAVER: Etiwanda 3 and 4. And  
3 it's been, information on that needs to be really,  
4 really current, and mine's only a couple days old,  
5 and -- it's a couple days old and more gossip than  
6 actual information, but the ISO is here and can  
7 tell us what they expect with regards to Etiwanda,  
8 where that stands.

9 There's limited access to new capacity  
10 in the Southwest. The Southwest has added an  
11 incredible amount of capacity in the last 12  
12 months. However, we can't get to it during peak  
13 hours, or it, more accurately, it can't get to us.  
14 There is a reduction of transfer capability on the  
15 DC intertie from the Northwest, where from 3100  
16 megawatts PTC down to 2,000 during the summer,  
17 that will drop to zero for Q4. That probably has  
18 slightly less of an impact than the 1100 megawatt  
19 difference than the PTC indicates, but  
20 nevertheless, every megawatt counts.

21 We've experienced higher than expected  
22 load growth, beginning in, roughly in October of  
23 last year, especially in southern California.  
24 This is, seems to be due to our economic recovery.  
25 We expect above average temperatures this summer.

1 According to the Scripps Oceanographic Institute  
2 it's going to be very, very warm. And we have  
3 below average hydro conditions in both California  
4 and the Northwest.

5 The latter is more of an energy problem  
6 than a capacity problem. We've been informed by  
7 the Bonneville Power Administration that the  
8 binding constraint on imports into California is  
9 going to be the transmission system. They expect  
10 to be able to keep the transmission lines full all  
11 the way through and including September of this  
12 year. This means that the reduction in transfer  
13 capability on the DC intertie will be driving the  
14 reduction in the ability of California in import  
15 energy.

16 We have -- the below average hydro  
17 conditions in California are not, not going to  
18 affect capacity until probably late August or  
19 September. There are also reductions in  
20 deliveries from the Southwest, the Colorado River  
21 Basin, those are going to have an impact. In  
22 total, all these are going to result in our  
23 relying more on gas-fired power plants during the  
24 summer and, by definition, aging gas-fired power  
25 plants.

1           In the short run, and by short run I  
2       mean through 2005 and 2006, the state doesn't have  
3       alternatives to reliance on aging power plants.  
4       We expect optimistically somewhere in the  
5       neighborhood of -- the upper bound would be about  
6       4500 megawatts of capacity to be added through  
7       2006. This is going to include -- and I said  
8       optimistically -- Mountain View, Palomar, several  
9       municipal facilities, Ripon, Marlburg, Salton Sea  
10      6 is going to come online, hopefully by summer of  
11      2006, so 170 megawatt contract with IID.

12           One of the irrigation districts is  
13      bringing Walnut online, and you could add to this  
14      SMUD Cosumnes should be online by summer of 2005.  
15      We think Metcalf will be online by summer of 2005.  
16      Magnolia. I, I expressed some concerns about  
17      Pastoria at the, the last time I made this  
18      presentation. Those really haven't been  
19      alleviated. I believe that people are assuming it  
20      will come online, but I, I have my doubts.

21           But, despite 4600 megawatts of potential  
22      new additions, Mojave's going to be taken offline  
23      at the end of 2005. Hunter's Point is another 220  
24      megawatts which will be gone. We, we don't  
25      anticipate any transmission upgrades which will

1       reduce the RMR needs of the ISO. There certainly  
2       hasn't been a reduction based on the 2005  
3       technical study. The statewide RMR needs are  
4       actually up a couple hundred megawatts for 2005,  
5       compared to this year. We'd welcome any comments  
6       from the ISO regarding potential reductions in RMR  
7       needs for 2006.

8               There, we do not expect any upgrades  
9       which will markedly increase our access to power  
10      outside the state of California. The transmission  
11      lag is a little longer than two years, despite our  
12      efforts to shorten it. And the preferred  
13      resources expressed in the EAP, demand side energy  
14      efficiency, critical peak pricing, and all the  
15      other demand side programs which are going to  
16      reduce capacity needs, are, most of those targets  
17      are, are for 2008. The incremental targets, while  
18      achievable, are not so substantial as to markedly  
19      reduce our dependence on generation in the next  
20      couple years.

21             In other words, we're still going to  
22      need these plants in the next two years, and if we  
23      were to experience a substantial amount of  
24      retirements the state would be in serious trouble,  
25      from a reliability perspective.

1           Aging power plants have a series of  
2   revenue sources. One DWR contract ensures a  
3   revenue stream for a set of AES units. Contract's  
4   administered by San Diego, it's a Williams  
5   contract, there are, I believe, three Alamitos  
6   units, a Huntington Beach unit, and a Redondo  
7   Beach unit, which are all under contract. Several  
8   older units in local reliability areas have RMR  
9   contracts. I think that's about 4300 megawatts of  
10   a sample under study. And as, as noted earlier,  
11   it is very likely that these units will continue  
12   to have RMR contracts through 2006.

13           So in, as an aside, this brings out  
14   total amount of capacity at risk in the  
15   neighborhood of about 7500 megawatts. We have  
16   17,000 megawatts in the study. Removing 2300  
17   megawatts of muni units, 1500 megawatts of  
18   capacity under the, the Williams RMR contract, and  
19   another 4300 megawatts of RMR capacity, get you  
20   down to about 7500 megawatts, 8,000 megawatts of  
21   capacity that's, that's truly at risk of retiring.

22           CHAIRPERSON GEESMAN: That's because  
23   you're, you're assuming that that plant with an  
24   RMR contract now will continue to hold an RMR  
25   contract during the study period?

1           MR. VIDAVER: That, it's assumed that  
2           that will, that will be the case through 2006.  
3           But we, we would defer to the ISO regarding what  
4           is likely to happen to plants that have existing  
5           RMR contracts that are denied contracts, or, or no  
6           longer offered contracts due to either  
7           transmission upgrades or, more likely, the  
8           construction of new power plants in local  
9           reliability areas such as Metcalf, Palomar.

10           We haven't gotten to the point in the  
11           study where we can make any definitive statements  
12           about whether or not these plants will, will, for  
13           example, Encina would lose an RMR contract should  
14           Palomar be built, or whether Pittsburg 7 would  
15           lose an RMR contract should Metcalf be built. We  
16           haven't proceeded that far. There may be, there  
17           may be reasons beyond RMR contracts that these  
18           plants would still be needed. But I'm not, I  
19           defer to the ISO on, on that.

20           Prices in real time energy markets  
21           during non-summer months will remain below the  
22           operating costs of most aging power plants.  
23           Absent -- I don't want to get in trouble for  
24           saying this, but absent, absent high spot market  
25           prices during the summer for the next couple of

1 year, the profit streams of aging power plants may  
2 not look very good.

3 CHAIRPERSON GEESMAN: But when you say  
4 high prices, you mean high spark spreads, don't  
5 you, because high prices --

6 MR. VIDAVER: Yeah. It's, it's, when I  
7 say high prices, I mean prices well, well above,  
8 let's say, an implicit heat rate of 10,000. Yeah.  
9 It's -- high prices are, are relative to the price  
10 of gas, and right now we have gas sitting about  
11 620, so -- an implicit rate of 11,000, which is  
12 \$70 in the, in the spot market. Absent prices in  
13 the \$90 to \$100 range sustained over the summer,  
14 it's difficult to imagine plants that are relying  
15 totally on energy markets turning over a profit  
16 during the next two summers.

17 And, again, plants are, aging plants are  
18 often called under must-offer. Must-offer pays  
19 variable costs, but does, among other things, to  
20 date it has provided a disincentive for  
21 participating in ancillary service markets. The  
22 ISO has recently requested a tariff change at FERC  
23 that will allow plants under must-offer to  
24 participate in ancillary service markets.

25 CHAIRPERSON GEESMAN: What are the, what

1 are the major capital upgrades that you've got  
2 contemplated during there in your second bullet?

3 MR. VIDAVER: I, I don't have any  
4 particular upgrades in mind. We've talked to --  
5 Matt is perhaps a better person to answer that  
6 question. He's talked to, he's talked more to the  
7 generators than I have.

8 CHAIRPERSON GEESMAN: Okay.

9 MR. VIDAVER: They, they claim that,  
10 that due to the age of the plants, the substantial  
11 capital upgrades are necessary to continue  
12 operation. Exactly what those are, Matt probably  
13 has a much better handle on than I do.

14 CHAIRPERSON GEESMAN: Okay. Well, maybe  
15 he could address it, then.

16 MR. TRASK: Yeah. A lot of the merchant  
17 generators are, are investing in their plants to  
18 simply make them more efficient. They're  
19 rewinding generators, they're installing new  
20 exciter fields, they're installing new turbine  
21 blades, all to get more longevity as well as  
22 efficiency out of these units. The ISO could  
23 probably speak to this a little bit better, but  
24 they, from what I understand, the RMR contracts,  
25 they will pay for needed repairs and so forth, say

1 a valve goes out.

2 But for the upgrades that aren't  
3 essential for continuing the RMR service, the ISO  
4 does not automatically grant those, those cost  
5 recovery. So it does, in a sense, discourage  
6 major capital upgrades for an inefficient RMR  
7 unit.

8 CHAIRPERSON GEESMAN: Okay. Thanks.

9 MR. VIDAVER: There are incentives for  
10 aging generators to remain online. The major one  
11 at this point is -- probably one of the major ones  
12 is potential for higher prices in the near term  
13 due to a tightening supply/demand balance,  
14 especially in SB 15. We've looked at the over the  
15 counter forward prices for the next couple of  
16 years, and the spark spreads arise in the implicit  
17 heat rates are into the 12 to 13,000 range for Q3  
18 of '04 and calendar -- excuse me, Q3 '05 and  
19 calendar '06. Admittedly, these prices don't  
20 really constitute an expected market clearing  
21 price. They, they're pretty illiquid, and, and  
22 reflect the concerns they're perhaps the most risk  
23 averse buyers in the system.

24 There are costs of, of retirement, one  
25 of which is you can't change your mind. And there

1 are costs associated with mothballing facilities,  
2 depending on how long it will take you to get back  
3 up. If you're talking about six months and April  
4 rolls around and forward prices indicate it would  
5 be a very profitable summer, you've just foregone  
6 a profit opportunity.

7 CHAIRPERSON GEESMAN: Sounds, though,  
8 like we may have been able to turn on a dime more  
9 quickly with respect to Etiwanda than that.

10 MR. VIDAVER: Yeah. I, I'll leave it up  
11 to the ISO to comment on that. I don't, I don't  
12 know exactly where Etiwanda stands at the moment,  
13 and I'm not, I'm not sure the ISO has, would like  
14 to go forward with a, a reliability management  
15 program that requires a level of fervent activity  
16 that Etiwanda seems to have required.

17 Indeed, if Etiwanda 3 and 4 do come back  
18 online this summer, it may be proof positive that  
19 we can respond outside of sort of normal channels  
20 to suddenly occurring reliability crises, which  
21 would be a good thing. But again, I'll leave that  
22 to, to the ISO to discuss.

23 MD02 -- I can't believe we're still  
24 calling it MD02 -- is -- locational marginal  
25 pricing is, is expected to be put into place, I

1 believe sometime in '06. It is my understanding  
2 that the preliminary simulations done to assess  
3 the likely impacts of LMP indicate a price premium  
4 for plants located near load centers. These would  
5 include the aging, many of the aging power plants  
6 in the study in the L.A. Basin.

7 CHAIRPERSON GEESMAN: Now, have, have  
8 you seen any such simulations?

9 MR. VIDAVER: I personally have not seen  
10 them, but, then again, I try and avoid looking at  
11 hundreds of pages of, of spreadsheet data whenever  
12 I can.

13 CHAIRPERSON GEESMAN: Are, are they  
14 publicly available?

15 MR. VIDAVER: I believe they are. Mr.  
16 Pettingill? We can defer that to the ISO.

17 MR. PETTINGILL: I think it's a --

18 CHAIRPERSON GEESMAN: You need to come  
19 to a mic. I'm sorry.

20 MR. PETTINGILL: Sorry. I think the, I  
21 think it's my understanding that the study results  
22 of potential LMP prices have been made public. SO  
23 that some of the points that Dave's making would,  
24 would be available for folks.

25 CHAIRPERSON GEESMAN: And that would be

1 on a plant specific basis?

2 MR. PETTINGILL: I don't, I don't  
3 believe it's on a plant specific basis. But I,  
4 I'm not familiar with the details of the studies.

5 CHAIRPERSON GEESMAN: Okay. Thanks.  
6 You should identify yourself for the reporter.

7 MR. PETTINGILL: I'll give him my card.

8 CHAIRPERSON GEESMAN: Great.

9 MR. VIDAVER: Finally, an additional  
10 incentive to remain online is the possibility of  
11 contracts with load serving entities. Pursuant to  
12 the adoption and implementation of formal resource  
13 adequacy requirements, the word possibility refers  
14 to the, the potential for any individual generator  
15 to enter into that contract. We assume, despite  
16 the snail-like pace which it appears to be  
17 proceeding with, these formal resource adequacy  
18 requirements will be imposed.

19 The, the question then becomes when the  
20 effective date of those requirements, what the  
21 effective date of those requirements will be.  
22 Right now it's scheduled to be 15 to 17 percent by  
23 January 2008. Commissioners Geesman and Peavey  
24 have requested that that be moved up to 2006. So  
25 this is perhaps at this point the, the primary

1 incentive for, for aging power plants to remain  
2 online.

3 At least two of the investor-owned  
4 utilities have already issued requests for offer  
5 for capacity and/or energy for as far out as 2007.  
6 The current state of the resource adequacy  
7 proceedings at the PUC are such that -- and the  
8 procurement proceeding, are such that the  
9 utilities are currently allowed to enter into  
10 five-year contracts for delivery beginning in  
11 2004, for a share of their residual net short.  
12 They're also able to enter into one-year contracts  
13 for delivery beginning in the first three quarters  
14 of 2005. And I'll go into more detail about the  
15 increasing size of the residual on net short in  
16 the next slide.

17 As I mentioned, the utilities will be  
18 required to meet 15 to 17 percent planning reserve  
19 margin requirements in 2008, with interim  
20 requirements to be determined. They'll be  
21 required to meet 90 percent of this requirement  
22 one year forward. They are likely to be required  
23 to meet these requirements in each local  
24 reliability area, and they are likely to have to  
25 meet these requirements in such a way that

1 deliverability of the energy is assured. Both of  
2 the latter two apparently being discussed in the  
3 resource adequacy proceedings at the PUC, if  
4 adopted, are apt to increase the need for in-state  
5 generation, and therefore increase the reliability  
6 on aging power plants absent the construction of  
7 new facilities.

8 MS. JONES: Dave, when you talk about  
9 local reliability areas, how many are you speaking  
10 of for the state?

11 MR. VIDAVER: Catalin, I just whacked a  
12 couple off. How many are there now? Nine. I got  
13 rid of two this year, I think. So of, of concern  
14 in this study are the San Diego local reliability  
15 area, the local -- the active local reliability  
16 are in the L.A. Basin, the San Francisco proper,  
17 and Greater Bay Area local reliability areas, and  
18 Humboldt. So there are a series of local  
19 reliability areas in the Central Valley that, that  
20 sort of revolve around hydro and don't really  
21 concern aging power plants.

22 CHAIRPERSON GEESMAN: When you speak of  
23 the likely increased need for in-state generation  
24 caused by the deliverability requirement, is that  
25 because of anticipated congestion on the

1       interties?

2               MR. VIDAVER:  Yeah, for, for assets  
3       located outside the -- assets, physical assets or  
4       contracts with assets located outside the ISO  
5       control area, the ability to move energy over the  
6       intertie is a concern.  In the absence of any  
7       definitive statements regarding the eligibility of  
8       assets outside the ISO control area or contracts  
9       with assets outside the ISO control area, it's my  
10      opinion that the load-serving entities in-state  
11      will only enter into contracts with physical  
12      resources that -- for which deliverability is  
13      assured, and that either requires it to be inside  
14      the ISO control area and can deliver to aggregate  
15      load.

16             Or it requires a, a series of -- meeting  
17      a series of requirements for, for assets located  
18      outside the state that are sufficiently stringent  
19      so as to assure that when deliverability is  
20      finally dealt with, that those assets will,  
21      indeed, meet whatever, however stringent  
22      requirements might be imposed.

23             So we're talking about the willingness  
24      of an IOU or a load-serving entity in California  
25      to enter into a contract with, with a generator

1 located outside of California, but the generator  
2 will have to prove that he has assets, firm  
3 transmission capacity to the intertie, and the,  
4 the counterpart of the contract will -- may also  
5 have to prove the ownership or physical control  
6 over an asset located outside the ISO control  
7 area.

8 When you compare that to a much less  
9 stringent requirement for, for a contract with a  
10 counterparty inside of California, this bodes well  
11 for an aging power plant, rather than someone who  
12 has yet to set up all the ducks in a row to ensure  
13 deliverability.

14 CHAIRPERSON GEESMAN: Okay.

15 MR. VIDAVER: To the extent that aging,  
16 the owners of aging power plants are, are hoping  
17 that to enter into contracts for, for energy  
18 products with IOUs and other load-serving entities  
19 in California, they will have to be able to meet  
20 the -- to provide the products that these entities  
21 need. At the moment there's a need for Q3 peaking  
22 capacity.

23 I have to speak in generalities here.  
24 The, Edison has, Southern California Edison has  
25 issued an RFO for three separate products for

1       either -- for up to three years starting in 2004,  
2       or for up to one year starting in the first three  
3       quarters of 2005. And these products are super-  
4       peaking capacity, basically, I guess it's seven by  
5       eight products for Q3 in 2004, peaking capacity,  
6       six by sixteen in 2004, and I believe the other  
7       product is -- I'm going to take a guess, I've  
8       forgotten what it is.

9               But in any case, the, the utilities  
10       right now have a need to a greater or lesser  
11       extent primarily for Q3 peaking capacity. As DWR  
12       contracts expire, QFs come offline, load grows,  
13       the number of products which the utilities will be  
14       seeking will increase. It will move from capacity  
15       to energy, and it will move from Q3 to all  
16       quarters of the year over subsequent years.

17              Right now, despite the ability of, of  
18       the utilities to enter into five-year contracts,  
19       the Southern California Edison RFO has, has  
20       solicited three-year products. One reason for  
21       this is the uncertainty of load obligations. The  
22       utilities are hesitant to enter into long-term  
23       contracts for what ultimately may prove to be  
24       stranded assets.

25              There is a, another possible motive

1       which includes the fact that after three years  
2       there might be a greater number of counterparties  
3       with which to deal. There is certainly the  
4       possibility that new power plants will have come  
5       online. That, in a nutshell, that the terms of  
6       the contracts might be more favorable to buyers  
7       three years down the road. That's, no one has  
8       told me that, that's -- just seems to be rather  
9       obvious to me.

10               CHAIRPERSON GEESMAN: With respect to  
11       your first bullet, if I recall correctly, you made  
12       the same statement in May. I see that the staff  
13       has recently revised its projections for '04.  
14       Would I be correct in understanding that you'd see  
15       a greater need in Q3 '04 than you did in May?

16               MR. VIDAVER: To the extent that the  
17       utilities have revised their assessments of what  
18       their loads are during the summer, that would be  
19       the case. But I imagine that that higher than  
20       expected load growth is probably something the  
21       utilities were aware of well before May. I, I'm  
22       trying to recall any particular incident, but I  
23       don't really think that the, that there has been a  
24       change in the expected requirements for energy or  
25       capacity in the last six weeks. The only thing

1       that has changed, to my mind, is the possible  
2       reappearance of Etiwanda. But that really has --  
3       doesn't have an impact on the need for capacity as  
4       much as it does on the supply of it.

5               So I would, I would think that major  
6       revisions to the capacity needs probably occurred  
7       sometime much earlier in the year, or in Q4 of  
8       last year, when load growth, when load information  
9       realized, made it apparent that loads in southern  
10      California were probably growing faster than  
11      anyone had anticipated. To my, my knowledge, I  
12      don't think any, any other existing physical or  
13      contractual asset has disappeared in the last six  
14      months, so.

15             CHAIRPERSON GEESMAN: And would you  
16      change your projection for '05 based on the, the  
17      staff revised forecast?

18             MR. VIDAVER: I might change my  
19      projection about the state's supply/demand  
20      balance. I might -- and I would change my  
21      projection about reserve margins SP15. They were,  
22      they fell as a result of the realization that  
23      loads are probably -- are growing faster than we  
24      anticipated, and to the -- if Etiwanda 3 and 4 are  
25      indeed available for this summer, which we assumed

1 as of the conclusion of the, the auction held by  
2 Reliant last October, we assumed they wouldn't be  
3 available. So I, my feeling is it's probably a  
4 wash. You're probably getting 800 more megawatts  
5 of capacity and something on the order of four or  
6 500 more megawatts of, of peak load in SB15,  
7 relative to what you assumed, let's say, in  
8 November of October of last year.

9 I, I don't work on the demand side, so I  
10 really don't know the extent to which we've  
11 revised our assumptions about SB15 peak loads.

12 The, the question arises, then, to what  
13 extent can the aging power plants provide the  
14 products the load-serving entities need. To the  
15 extent that quick start capacity for Q3 is, is  
16 what load-serving entities are actively soliciting  
17 right now, we have a slight problem in that aging  
18 power plants aren't, aren't designed to provide  
19 this product.

20 To the extent that that same product is  
21 needed next year, the -- and the load-serving  
22 entities are under obligations to meet reserve  
23 margin requirements, there may be no alternatives  
24 to aging power plants, and the utilities may have  
25 to, to work products into their resource mix that

1 may not necessarily result in the lowest cost to  
2 ratepayers. Meaning that if you need to meet a  
3 reserve margin requirement and you have to pay a  
4 slow start unit to provide you what -- the  
5 capacity that you want, and you want quick-start  
6 peaking capacity, you're sort of between a rock  
7 and a hard place.

8 Now, this is, this is not to say that  
9 the, that the potential cost to ratepayers of  
10 relying on, on slow-start steam turbines to  
11 provide, to provide energy products is necessarily  
12 that high. As Matt mentioned, the, for example,  
13 existing aging steam turbines can provide cycling  
14 energy at, at roughly the same cost as a new  
15 combined cycle, due to the fact that the combined  
16 cycle operates at a very high heat rate at low  
17 output levels, whereas most steam turbines have a  
18 rather flat heat rate over their range of output.

19 The question becomes can these aging  
20 power plants competitively provide those products  
21 that will be needed, let's say, in 2006, 2007, and  
22 2008. The answer to this question is probably  
23 yes. That the products needed by the IOUs and  
24 other load-serving entities, two, three, four  
25 years down the road, will probably be very similar

1 to those products that, that aging power plants  
2 can provide.

3 The, a more important question for  
4 ratepayers is probably will there be alternative  
5 sources for these products. Will we have new  
6 generation that comes online that can provide  
7 this, these resources more efficiently and  
8 therefore cheaply than, than existing power  
9 plants. And if these products, these new  
10 resources aren't available, to what extent will  
11 the, the -- will products in contractual forms be  
12 developed by load-serving entities that allow them  
13 to incorporate aging power plants into their  
14 portfolio at a minimal cost to ratepayers.

15 So that's, that's that. I think I'm  
16 done. Yes, I know nothing about transmission, so.

17 I'd, I'd like to offer a concluding  
18 comment. I think that I'm, I'm reasonably  
19 optimistic about the, the continued availability  
20 of existing power plants based on what I've seen,  
21 and I speak only for myself. But that has to be  
22 caveated. The risk that I'm wrong is, is  
23 substantial. Even if the probability that I'm  
24 wrong is small, and you can take issue with that,  
25 certainly the cost of being wrong could be

1 catastrophic.

2           So in, in saying that I, I think that  
3 there is a sufficient amount of uncertainty going  
4 forward as well as simultaneously enough structure  
5 so that aging power plants will remain around for  
6 the next 24 months, if only to see what happens.  
7 But if I'm wrong, the lights go out. So you can  
8 take my opinion for what it's worth. And that,  
9 again, it's only my opinion.

10           CHAIRPERSON GEESMAN: Thanks, Dave.

11           MR. VIDAVER: So I'm done.

12           MR. TRASK: The next topic is talking  
13 about reliability investigation as we complete the  
14 aging plant study. I apologize, I managed to  
15 sprain my ankle doing yard work.

16           As I mentioned earlier, we're analyzing  
17 a very wide range of possible retirements of these  
18 aging units. As Dave mentioned, we're essentially  
19 assuming that if a, if a unit has an RMR contract,  
20 that it will not retire as long as it has that RMR  
21 contract. As he mentioned, there are units that  
22 are under contract through DWR contracts. We're  
23 assuming that those will not retire through the  
24 term of those contracts.

25           So essentially, we're left with about

1 7500 megawatts of capacity that we think are, are  
2 somewhat at risk of retirement. So we are looking  
3 at the role that these aging plants play in both  
4 providing reliability services and also in, in  
5 alleviating transmission circuit congestion. This  
6 is a phenomenon down in the Los Angeles area,  
7 predominantly, where you have about five or six  
8 interties bringing power in to supply local load  
9 there in the Edison and LADWP territory. Those  
10 interties can, can become quite congested, and  
11 they can be in combinations.

12 You could see that five out of the six  
13 are, are congested, two out of the five, or  
14 whatever. And depending on the combinations of  
15 congestion, the control area operators will pick  
16 certain units to help alleviate those congestions.  
17 And depending on which lines are congested on  
18 which day, it could be a different unit on each  
19 different day.

20 CHAIRPERSON GEESMAN: How specific can  
21 you get as it relates to those transmission  
22 circuit congestion problems?

23 MR. TRASK: We think we can get fairly  
24 specific. One of the things we're getting from  
25 the ISO is their operating procedures, what they

1 do on any given day when they start to see these  
2 congestion -- congested lines. Part of that is  
3 that most of the units down there have a, a  
4 momentum rating which essentially describes their  
5 ability to alleviate this congestion or to supply  
6 local load, and how quickly they can do it. So  
7 the units that generally have the higher momentum  
8 ratings are the ones that are more used and useful  
9 in, in this situation, alleviating congestion.

10 CHAIRPERSON GEESMAN: And I, I presume  
11 there are transmission upgrades, you know, perhaps  
12 which, which are no, no larger than those that  
13 would be covered by G0131, that would potentially  
14 serve as, as an alternative means of alleviating  
15 congestion, in contrast to continued operation of  
16 these plants?

17 MR. TRASK: Certainly that, that's a  
18 possibility. So far we haven't seen any that  
19 would have a major effect on, on this process.  
20 For instance, up in the Humboldt region we know  
21 that there was a small transmission upgrade there  
22 that allowed PG&E to shut down a remote start  
23 peaker that was sitting about, I think, 40 or 50  
24 miles south of the Humboldt plant on the coast  
25 there. They did a minor transmission upgrade that

1       allowed them to not need that little peaker.

2               But as far as we've seen, there's  
3       nothing in the time period that we're looking at,  
4       through 2008, that, that would affect the -- that  
5       would change the operating procedures that the  
6       control area operators use to alleviate  
7       congestion.

8               CHAIRPERSON GEESMAN:   And do you  
9       envision us in this study getting to a level of  
10      granularity, where we're able to, to actually make  
11      that assessment in terms of various transmission  
12      upgrades?   And I, I'll call them small  
13      transmission upgrades.

14              MR. TRASK:   It, it's certainly something  
15      that, that is pretty high on our, on our list as  
16      far as talking with folks, with ISO and with the  
17      utilities themselves.   And, like I said, to date  
18      we haven't heard of any planned upgrade that would  
19      change the situation.

20              CHAIRPERSON GEESMAN:   Okay.   Thank you.

21              MR. TRASK:   As Dave mentioned, we're  
22      also strongly studying anything that could  
23      possibly affect the RMR status in the aging units.  
24      Those are primarily limited to any transmission  
25      upgrades.   And again, we don't know of any big

1 ones that are likely to be completed by 2008,  
2 other than possibly Valley Rainbow. And then new  
3 power plants. The, as a new power plant comes  
4 online and takes away an RMR contract from an  
5 older unit, we don't generally consider that a  
6 reliability concern, because it is a, a megawatt,  
7 four megawatt replacement.

8 We are coordinating with the, with the  
9 ISO on the study of reliability effects. One  
10 fortunate thing we found out was that the ISO  
11 essentially is conducting the exact study that we  
12 need for this study, the aging power plant study.  
13 It's part of their annual grid assessment study,  
14 which they do every year. About the only  
15 difference in this one is that they are, indeed,  
16 looking at the impacts of potential plant  
17 retirements, and it happens to be almost exactly  
18 the same units that we're looking at.

19 These studies are usually completed in  
20 the fall. They require quite a bit of input from  
21 utilities themselves, and the utilities are doing  
22 that right now. They are expected to be  
23 submitting that information in early fall, and the  
24 studies will be complete probably more like  
25 October, November.

1           Again, this is more on, on that study.  
2           It's a stakeholder process, a very wide range of  
3           participants. They look at about five years out,  
4           plus sort of an added analysis. They look at the  
5           tenth year for reliability violations. And then  
6           they come out that with steps that are needed to  
7           avoid violations.

8           CHAIRPERSON GEESMAN: If we're on a  
9           calendar to adopt recommendations to the Governor  
10          and the Legislature November 1, is there some way  
11          in which these two processes can be harmonized so  
12          that before November 1 we have the benefit of at  
13          least some fairly semi-final drafts of the ISO  
14          work?

15          MR. TRASK: We're, we're coordinating  
16          with the ISO on that, and we're, that's certainly  
17          a goal. The limiting factor there is that they  
18          can't get started until they get the data from the  
19          utilities. So until they get that data, they  
20          can't even start, and that's not expected until  
21          probably September or so.

22          CHAIRPERSON GEESMAN: Okay.

23          MR. TRASK: Just further on the ISO  
24          studies here. When I talk about reliability  
25          violations, that comes out of an earth-planning

1 standards as well as the WCC and the ISO's own  
2 planning standards. This is the web address here  
3 on the bottom. You can find all the assumptions  
4 that the ISO is using for that study. For you  
5 folks on the internet, this presentation is  
6 already posted on the internet under the May 18th  
7 workshop on the IEPR website. There's been a few  
8 changes and we will re-post it today sometime.

9 Here's the specific retirement scenarios  
10 that the ISO is looking at in that study. Again,  
11 focused in, in the local reliability areas that,  
12 that we are also focused in. This one, as you can  
13 see, is looking at Contra Costa units 4, 5, 6 and  
14 7, Pittsburg 5, 6 and 7, Moss Landing, Potrero,  
15 Morro Bay, Ormond Beach and Mandalay. Then, of  
16 course, the -- San Diego area, looking at the  
17 Encina. Again, they're all the exact same units  
18 that we're looking for, Orange County and South  
19 Bay.

20 These are some of the other assumptions  
21 that they're using in that study, 530 -- 5324  
22 megawatts of retired or mothballed plants already,  
23 and expected of almost 3700 megawatts to retire in  
24 the near future. The exception there, of course,  
25 is now Etiwanda 1 and 2 has changed. Or, excuse

1 me, 3 and 4.

2 MS. JONES: Matt, can I ask, of the  
3 retired and mothballed, how many of them are  
4 mothballed versus permanently retired?

5 MR. TRASK: Very few. In fact, I  
6 believe it's only the Etiwanda and Morro Bay units  
7 are officially mothballed.

8 MS. JONES: Thank you.

9 MR. TRASK: Dave talked about that. One  
10 of the reasons is if you mothball them you can  
11 lose your emission reduction credits, because  
12 they're based on operation rather than capacity.

13 Moving the wrong button here. Again,  
14 further assumptions on that ISO study. Some of  
15 the things that they're, they're assuming will or  
16 will not be available, shows many of the LADWP  
17 units are being re-powered. Hunter's Point, of  
18 course, is being shut down as soon as possible.

19 Okay. That, that concludes our  
20 presentations on the electricity side of the, of  
21 our analysis. And now we'd like to get into the  
22 environmental side, starting first with Matt  
23 Layton on air quality.

24 MR. LAYTON: Good morning. My name's  
25 Matt Layton, I'm with the Air Unit of the Siting

1 Division of the Energy Commission. This is a  
2 brief overview of the California generation and  
3 air emissions. This kind of summarizes work we've  
4 been doing on these aging units, but also it goes  
5 back and pulled some work out of the 2001  
6 environmental performance report, and the 2003  
7 environmental performance report.

8 What we found about California  
9 generation is that the emissions, these are  
10 criteria pollutants, those that have health,  
11 health based standards associated with them, are  
12 relatively low for the generating units in the  
13 state. The reason for this is a predominance of  
14 natural gas and also a broad use of emission  
15 controls. Most of the units have been retrofit,  
16 or switched from fuel oil to natural gas. A lot  
17 of this occurred in the seventies, when,  
18 obviously, there was an oil shortage. And the  
19 result is relative to other states, and relative  
20 to past performance, California generation is a  
21 very, California generation emits at very low  
22 levels.

23 We expect the trend to continue. We  
24 have regulations in place that are continued to --  
25 require additional retrofits, not very many, but

1       also there's no backsliding. And natural gas, new  
2       natural gas units coming online are, of course,  
3       cleaner than the averages and more efficient. So  
4       on a per megawatt hour basis, we expect emissions  
5       to be decreasing.

6               CHAIRPERSON GEESMAN: What retrofits are  
7       you talking about? In this plant population.

8               MR. LAYTON: Potrero 3 is going down in  
9       September for SCR. Pittsburg 7 and Contra Costa  
10      6, or the other way around, I forget, it's Contra  
11      Costa 6 and Pittsburg 7 do not have SCR currently.  
12      The owners anticipate being able to comply with  
13      the retrofit rule in the Bay Area without SCR at  
14      this point in time. Again, how much those units  
15      run may dictate whether or not they go back and  
16      put SCR on those units.

17              There are, the ARB looked at trying to  
18      come up with a model rule, a retrofit rule for  
19      some of the combustion turbines. Most of the  
20      combustion turbines in the state, the peakers,  
21      were not subject to retrofit rules when these  
22      other retrofit rules for the boilers were --

23              CHAIRPERSON GEESMAN: They're not part  
24      of our study population.

25              MR. LAYTON: No, but, again, in general,

1 the emissions from the sector are good and getting  
2 better. If they go back and revisit the peakers,  
3 there may be opportunities for additional emission  
4 reductions from the generation sector as a whole.

5 CHAIRPERSON GEESMAN: Good. But focused  
6 on our, our study population, do you envision any  
7 additional retrofits in the southern California  
8 plant?

9 MR. LAYTON: No, I do not.

10 CHAIRPERSON GEESMAN: Okay. Thanks.

11 MR. LAYTON: What we've seen, and this  
12 is for the aging power plants, NOx emission rates  
13 have gone down 80 to 90 percent. These boilers  
14 have required the installation of SCR statewide.  
15 They are almost fully implemented. Again, Morro  
16 Bay does not have SCR, but they shut down a couple  
17 of the units and are operating under a daily cap,  
18 so currently they don't need SCR to comply with  
19 the retrofit rule.

20 MS. JONES: Matt, when you talk about an  
21 80 to 90 percent reduction, from, what's the base  
22 that you're using to compare?

23 MR. LAYTON: Well, before they installed  
24 the SCR.

25 In the early nineties, the retrofit rule

1 came out of the Air Resources Board as a model. A  
2 lot of districts adopted that. What it required  
3 was basically about a 90 percent reduction going  
4 from about one pound per megawatt hour down to  
5 about .1 pounds per megawatt hour. That required  
6 the use of SCR on most of these units.

7 Humboldt does not have a retrofit rule.  
8 They don't have the same ozone problem that other  
9 parts of California do. They're operating  
10 currently about three and a half pounds per  
11 megawatt hour. So compared to some of the other  
12 boiler units, Humboldt is very dirty, but it  
13 doesn't present the same air quality problems that  
14 perhaps units in, say, South Coast, do.

15 PM10 emission rates are very low.  
16 Again, the use of natural gas is considered BACT,  
17 best available control technology for PM10, PM2.5.  
18 Almost all these boilers can only use natural gas.  
19 A few of them can burn, in emergencies, some fuel  
20 oil. That would be Humboldt, Potrero, Encina, and  
21 South Bay. They used to, in the past, be able to  
22 burn fuel oil for economic reasons. Again, now  
23 they're limited strictly for emergencies.

24 The goal to try and change gas emission  
25 rates for California are relatively low to other

1 states. Again, as a function of natural gas. We  
2 use a lot of natural gas. Other parts of the  
3 country use a lot of coal. Coal emits almost two  
4 times as much CO2 per unit of heat, energy. So  
5 California emits at a relatively low rate CO2  
6 emissions per megawatt hour.

7 ARB recently published a number saying  
8 that 90 percent of the -- 90 percent of  
9 Californians are still exposed to poor air quality  
10 at some time during the year. While air quality  
11 is improving in most parts of the state, it is  
12 slowing. We have continuing growth of population.  
13 So we expect that emission reductions will still  
14 be needed in various sectors. We expect the power  
15 plants, while having achieved significant  
16 reductions in emissions, will be considered for  
17 additional retrofits and reductions.

18 We don't know what those reductions  
19 might be. As Commissioner Geesman asked, I'm not  
20 aware of any new retrofit rules, but power plants  
21 generally are a large single source, single stack,  
22 and therefore sometimes can be the most cost  
23 effective reduction available.

24 South Coast is already considering  
25 modifying the reclaim rule, their BARCT rule for

1 NOx, and they're thinking about taking 5 to 15  
2 percent of the allocations currently granted to  
3 the units in southern California. The others we  
4 talked to did not believe that particular amount  
5 would severely constrain their ability to operate  
6 in the timeframe of this study through 2008.

7 Again, as I mentioned, the Air Resources  
8 Board had considered the retrofit rule to  
9 combustion -- for combustion turbines, but had  
10 not, has not completed that and probably will not  
11 complete that particular rule development.

12 Because of the great improvements in  
13 performance, the environmental, or the emissions  
14 performance of these units, these units have a  
15 limited impact on emissions in any one basin. And  
16 therefore, retiring these units may not  
17 necessarily provide an air quality benefit. What  
18 we're talking about here are actual emissions.

19 Most of these units on an annual basis  
20 operate about 20 percent. They are permitted for  
21 100 percent operation; therefore, 100 percent of  
22 their emissions. Their ability to emit is under-  
23 utilized at this point in time. They're only  
24 emitting 20 percent of their permitted value. If  
25 a new unit does come in, and is a baseload unit, a

1 combustion turbine combined cycle, which most  
2 people are trying to compare to these aging power  
3 plants, that combustion turbine combined cycle may  
4 want to operate as baseload.

5 If you replace an aging unit with a new  
6 plant at that site, you may see emissions from  
7 that site increase. Emissions in the basin may or  
8 may not increase or decrease. But these units are  
9 currently very clean, and not operating much. So  
10 I don't, we don't think that the retirement of  
11 these units will offer significant benefits of  
12 dis-benefits from an air quality perspective, or  
13 an air emissions perspective.

14 These aging power plants are located  
15 near populations, and therefore their emissions do  
16 affect air quality and public health. Regulators  
17 really only can affect air quality in most of  
18 California by reducing emissions. But, as I've  
19 said before, the emissions from these, these  
20 particular units are very, relatively low, and  
21 perhaps may not be the most cost effective  
22 reductions available to the regulators.

23 Also, if we were to retire these plants  
24 and electricity shortages were to occur if we  
25 didn't replace these plants, perhaps the shortages

1       could have more significant effects on public  
2       health than the air quality or the air emissions  
3       from this, this sector. And in 2003, the heat  
4       wave in Europe claimed 35,000 lives. The death  
5       rate in Paris on a usual summer day is about 30  
6       per day. During the heat wave, it was about 180 a  
7       day, a sixfold increase.

8               France and most of Europe don't rely  
9       much on air conditioning, so they didn't have that  
10      ability to turn to air conditioning. But in  
11      California, we do rely a lot on air conditioning.  
12      If there were shortages and air conditioning would  
13      fail in California, it could be a substantial  
14      public catastrophe. Currently, heat waves kill  
15      more people than other natural disasters such as  
16      hurricanes, tornadoes, floods, earthquakes.

17             CHAIRPERSON GEESMAN: Again, you  
18      suggested that there may be more cost effective  
19      ways of achieving emissions reductions. What did  
20      you have in mind?

21             MR. LAYTON: The mobile sector is still  
22      the largest contributor to --

23             CHAIRPERSON GEESMAN: Okay.

24             MR. LAYTON: It presents some problems.  
25      It's not --

1                   CHAIRPERSON GEESMAN: Were you  
2                   commenting at all on other stationary sources?

3                   MR. LAYTON: Other stationary sources do  
4                   offer opportunities, but even then the, depending  
5                   on which pollutant you're talking about, the  
6                   mobile sector is generally the dominant  
7                   contributor. In other cases, area sources are  
8                   dominant contributors. Area sources are very  
9                   difficult to control because, by their definition,  
10                  they're diffuse. Whether it's water heaters,  
11                  furnaces, or construction activity and unpaved  
12                  roads, for particulate matter.

13                  I guess the industrial contributions for  
14                  a lot of these pollutants is still not that great,  
15                  either. Curtailing industrial output or putting  
16                  retrofits on industrial processes may not get you  
17                  much in the way of reductions, either. Given that  
18                  we do need a lot of reductions, perhaps the sector  
19                  we want to look at is the mobile sector.

20                  CHAIRPERSON GEESMAN: You didn't, you  
21                  didn't have anything specific in the stationary  
22                  source sector.

23                  MR. LAYTON: I do not. I do not.

24                  CHAIRPERSON GEESMAN: Thanks.

25                  MR. LAYTON: I think this is my, my last

1 slide. The -- well, let's -- you've seen these  
2 before. In the other environmental performance  
3 reports we talked about air emissions on a  
4 statewide basis. And what I've done here is I've  
5 looked at PM2.5 on a statewide basis, and then on  
6 a Bay Area basis, and then on a San Francisco City  
7 and County basis, trying to show that the relative  
8 ratios hold consistently such that when we talk  
9 about air emissions and air emissions from the  
10 generation sector, the contributions are small.  
11 Statewide, PM2.5 is about one and a half percent  
12 of the total. In the Bay Area, it's about one and  
13 a half percent of the total, and in the City and  
14 County of San Francisco it's about one and a half  
15 percent of the total. Suggesting that significant  
16 reductions in this sector would not change the  
17 PM2.5 levels in the Bay area much.

18 Mr. Geesman, or Commissioner Geesman,  
19 you had asked me to look at NOx. Again, pie  
20 charts. NOx statewide is about two percent of the  
21 total looking at both the electrical facilities  
22 and cogeneration. Again, 80 percent of the NOx  
23 generated in the state, this is a statewide  
24 average, is from the mobile sector, on road and  
25 off road mobile.

1           Fuel combustion is about ten percent.  
2           That would be other industrial processes. In the  
3           sectors, how ARB puts various emission sources  
4           into a sector changes from year to year, so you,  
5           it would be better to group these things, fuel  
6           combustion is about ten percent. If we do improve  
7           fuel combustion we could probably get some  
8           reductions from that sector.

9           Looking at Bay Area NOx emissions, they  
10          do jump up higher than the two percent. They're  
11          about three and a half percent. The electric  
12          utilities in the Bay Area do contribute more than,  
13          say, the average and statewide. But then looking  
14          at the City and County of San Francisco, which has  
15          two aging facilities, Hunter's Point and Potrero,  
16          again, the numbers are about two percent of the  
17          total. The mobile sector, on road and off road,  
18          is about 92 percent of the emissions, NOx  
19          emissions in San Francisco proper.

20          So we believe that these aging power  
21          plants have limited effect on air quality. They  
22          use clean fuel. Most of the units are well  
23          controlled. And again, the contribution from this  
24          sector is relatively small to other sectors.  
25          There may be other opportunities for more cost

1 effective; retiring these units probably will not  
2 have much effect on air quality or air emissions.

3 CHAIRPERSON GEESMAN: Thank you, Matt.

4 MS. ALLEN: Good morning. I'm Eileen  
5 Allen from the Commission's Environmental Office.  
6 I'm going to be talking briefly about preliminary  
7 land use information that the staff has.

8 Regarding community concerns about the  
9 aging power plants, in talking with the  
10 communities where these plants are located we've  
11 concluded that there's one community, San  
12 Francisco, that has significant concerns about  
13 these power plants, particularly the Hunter's  
14 Point plant in southeast San Francisco.

15 In 2001, the San Francisco Board of  
16 Supervisors passed Ordinance 124-01, regarding  
17 human health and environmental protections for new  
18 electric generation. Among other features, this  
19 ordinance called for alternatives to fossil fuel  
20 generation and led to a city agreement with the  
21 Hunter's Point owner, PG&E, to shut down the  
22 Hunter's Point plant when it was no longer needed  
23 for system reliability.

24 In addition to local concerns about the  
25 Hunter's Point facility, some residents of the

1 southeast San Francisco area have concerns about  
2 continued operation of the Potrero facility, owned  
3 by Mirant, which is located approximately a mile  
4 away from the Hunter's Point area.

5 The City/County of San Francisco has  
6 recently filed an application with the Energy  
7 Commission for three proposed new generation units  
8 on the Potrero property. An informational hearing  
9 and site visit is scheduled for this project on  
10 Tuesday, June 15th, at 2:00 p.m.

11 As far as community planning efforts,  
12 the City of Redondo Beach and the City of Chula  
13 Vista have included the power plants in their  
14 communities in waterfront area community planning  
15 processes. The City of Redondo Beach's 1992 and  
16 2002 specific plans address the Redondo Beach  
17 plant. The Redondo Beach situation is somewhat in  
18 flux. The long-term outlook is somewhat  
19 speculative for the Redondo Beach power plant  
20 site, which is in the coastal zone there.

21 There's a possibility that this site  
22 with the plant will be rezoned to a non-industrial  
23 use. Currently, the 1992 specific plan is in  
24 place and it calls for non-industrial uses at the  
25 Redondo plant site. The AES Corporation that owns

1 the Redondo Beach plant is currently in discussion  
2 with the City of Redondo Beach about their current  
3 outlook and how they see things unfolding for the  
4 future.

5 A rezoning would require an amendment to  
6 the city's local coastal plan, and may involve  
7 some legal issues for AES, so they're in  
8 discussions with the city right now. For the  
9 purposes of this project, which has a timeframe up  
10 to 2008, we don't expect there to be any changes.  
11 So we will, also we'll be talking with the city  
12 about how they see things unfolding.

13 We are also aware of three possibilities  
14 for desalination projects that would be located  
15 adjacent to coastal power plants. These  
16 possibilities are at Moss Landing, Encina, and  
17 South Bay. Another desalination project was  
18 proposed at Huntington Beach. I've got some  
19 preliminary informal information that the City of  
20 Huntington Beach may have rejected the proposal  
21 for desalination there. That needs to be  
22 confirmed with the city. So we're looking at  
23 three possibilities for desalination that would  
24 make use of the existing once-through cooling  
25 facilities.

1                   That concludes the land use presentation  
2           for now. Do you have any questions?

3                   CHAIRPERSON GEESMAN; No. Thank you,  
4           Eileen.

5                   MS. ALLEN: Thank you.

6                   MR. TRASK: I'd like to turn attention  
7           to the biological analyses that were done, which  
8           is primarily limited to marine biology for the  
9           plants using once-through cooling. And to talk  
10          about that I have Dr. Noel Davis.

11                  DR. DAVIS: Okay, thanks.

12                  Eighty percent of the power plants that  
13          are the subject of this aging power plant study  
14          use once-through cooling, and once-through cooling  
15          is drawing water from an adjacent ocean, estuary,  
16          lake, or river to cool the units, and then in most  
17          cases the heated water is discharged back to the  
18          same water body.

19                  There are concerns about the impacts of  
20          once-through cooling on aquatic resources. And  
21          the primary concerns are related to impingement  
22          and entrainment at the intake. Impingement is  
23          when adult fishes or large invertebrates become  
24          stuck on the screen and either injured or, in most  
25          cases, killed. And entrainment refers to fish

1 larvae and other planktonic organisms that are  
2 small enough to pass through the screens, where  
3 they actually travel along with the cooling water  
4 and usually are injured or killed in the process.

5 The Federal Environmental -- the Federal  
6 Environmental Protection Agency, under the Section  
7 316(b) of the Clean Water Act, is required to  
8 establish the best technology available to reduce  
9 the impacts to aquatic resources from the intakes  
10 of power plants. And recently, in February of  
11 2004, they issued new regulations for 316(b). And  
12 what these regulations require basically is that  
13 all existing power plants that withdraw more than  
14 50 milligrams per day of cooling water meet  
15 performance standards. And those performance  
16 standards are that impingement impacts be 90, 80  
17 to 95 percent lower than uncontrolled levels, and  
18 the entrainment impacts be 60 to 90 percent lower  
19 than uncontrolled levels.

20 They, because EPA realizes that it is  
21 not simple, it may be quite difficult and quite  
22 expensive for existing power plants to retrofit  
23 their intakes or otherwise implement other  
24 measures to meet these performance standards,  
25 they've tried to be flexible by providing a range

1 of alternatives that any power plant can select to  
2 meet those performance standards.

3 The first way is to demonstrate that the  
4 facility has reduced cooling water flow  
5 commensurate with the flow of a closed cycle  
6 recirculating system. And any existing power  
7 plant that can demonstrate that they've done that  
8 is done. They don't have to do any further  
9 studies.

10 The next way to address impingement  
11 impacts is to demonstrate the facility has reduced  
12 the cooling water flow intake velocity to 0.5 feet  
13 per second. That gentle a flow has been shown to  
14 be highly protective of impingement. Fishes  
15 basically rarely become impinged at flows that  
16 long. A facility that has an intake velocity of  
17 0.5 feet per second or less does not have to do  
18 anything further to reduce impingement. However,  
19 they still have to address the entrainment  
20 performance standard.

21 The next alternative for meeting the  
22 performance standard is to demonstrate that the  
23 facility already has in place either design and  
24 construction technologies, operational measures,  
25 or habitat restoration measures that meet the

1 performance standard.

2 The next alternative is to demonstrate  
3 that they are going to implement design and  
4 construction technologies, operational measures,  
5 and/or habitat restoration measures that, along  
6 with any existing measures that they have, will  
7 meet the performance standards.

8 Another alternative is to demonstrate  
9 that the facility has installed and properly  
10 operates and maintains an approved technology.  
11 This was put in as an alternative because, based  
12 on comments, the Environmental Protection Agency  
13 wanted to provide a more streamlined way to meet  
14 the performance standards than the rather lengthy  
15 demonstration studies that are required for the  
16 previous two alternatives. And in this case,  
17 there would be certain technologies that had  
18 already been demonstrated that, if they were  
19 applied under certain circumstances a priori or  
20 assure they're meeting the standard, and so far  
21 only one such technology has been identified, and  
22 that's the use of fine mesh cylindrical wedge wire  
23 screens on freshwater rivers.

24 However, any regional water quality  
25 control board in the process, as these regulations

1 are implemented, may identify other technologies  
2 that will allow a facility to install one of those  
3 technologies, and thus have a much lower burden as  
4 far as demonstration studies go.

5 The final alternative is to demonstrate  
6 that a site specific determination of best  
7 technology available is appropriate. And what  
8 this means is basically that a facility can -- has  
9 the opportunity to demonstrate that for its  
10 particular facility, the cost of meeting the  
11 performance standard is either way  
12 disproportionate to what EPA had estimated in  
13 preparing the 316(b) regulations, or that the cost  
14 of meeting the performance standard was  
15 disproportionate to the benefit that would be  
16 received. And so if a facility can demonstrate a  
17 disproportionate cost, it may not be required to  
18 meet the performance standards. However, they  
19 still have to implement whatever technologies are  
20 practicable to reduce impingement and entrainment.

21 What we've been as -- what we've been  
22 doing for this study is we've been collecting  
23 information from owners of the aging power plants  
24 regarding the design of their intake, and the  
25 studies that they've done to address impingement

1 and entrainment impacts, and any measures that  
2 they have in place to reduce those impacts, as  
3 well as how they intend to comply with the new  
4 316(b) regulations.

5 Very few of the power plants in the  
6 study have intake velocities that meet the 0.5  
7 feet per second standard to reduce impingement.  
8 Most of the facilities either have never done a  
9 entrainment impact analysis at their facility, or  
10 their analyses are out of date. Most facilities  
11 do monitor impingement, although some of them  
12 haven't gone as far as analyzing what the impacts  
13 of that impingement might be.

14 There's a complete lack of analysis of  
15 the cumulative impacts of power plants that use  
16 once-through cooling and that are in close  
17 proximity to each other. For example, there are  
18 several power plants that are in Santa Monica Bay,  
19 and there are several parties who have commented  
20 that they believe that fishing opportunities could  
21 benefit from these regulations and the  
22 modernization of the intakes of power plants. No  
23 project owner that we've talked to so far has  
24 indicated that these new 316(b) regulations will  
25 lead to the closure of their facility. However,

1       some of them have indicated that if revenues were  
2       very low and the costs of complying were very  
3       high, it could encourage them to move towards  
4       retirement. No project owner so far has indicated  
5       that they intend to stop using once-through  
6       cooling.

7               All project owners that we've talked to  
8       intend to do whatever the new regulations require.  
9       And right now, because these regulations are so  
10      new and they haven't actually started being  
11      implemented yet, we don't really know what  
12      entirely all the implications of them all are, and  
13      what exactly it is that the regional water quality  
14      control boards are going to require.

15             It also should be pointed out that while  
16      there are adverse impacts to aquatic resources,  
17      particularly from these intakes in these once-  
18      through cooling systems, some of these aging power  
19      plants also do provide environmental benefits.  
20      And I've prepared a couple of examples.

21             The Encina Power Plant spends \$2 million  
22      every two years to dredge Agua Hedionda Lagoon,  
23      and it needs to do that to keep the lagoon open to  
24      maintain the integrity of its seawater intake  
25      system. But by doing that, they also improve

1 water quality in the lagoon, benefit the estuarian  
2 habitat, and the improved, or the maintain the  
3 high quality of the estuarian habitat has benefits  
4 to a lot of species, including the endangered  
5 California Least Tern that forages in Agua  
6 Hedionda Lagoon.

7 The Encina Power Plant also supports a  
8 white sea bass hatchery in the lagoon, and the  
9 power plant has participated in efforts to restore  
10 eel grass habitat to the lagoon, and to eliminate  
11 the invasive algae species colerpa. The Ormond  
12 Beach Power Plant has been working with groups  
13 that are trying to restore the Ormond Beach  
14 wetlands that are near the power plant. The power  
15 plant supports a marine laboratory that is raising  
16 abalone, and they also participate in other  
17 environmental efforts such as putting up signs to  
18 protect least tern and snowy plover nesting areas  
19 on the beach near the power plant.

20 Do you have any questions?

21 CHAIRPERSON GEESMAN: We had an  
22 extensive discussion at the last workshop as to  
23 timeframe for implementation of the new regs, and  
24 I believe, if I, if I can summarize correctly, it  
25 was the staff's conclusion that in our study

1 period between now and 2008, it was quite unlikely  
2 that the new regs would require any retrofit that  
3 would pose a significant risk of closing the  
4 plants.

5 DR. DAVIS: They're, the regulations are  
6 quite complicated, but they do provide a timeframe  
7 to comply, which gives the operators several years  
8 to comply with the regulations. They also give  
9 them the ability to use adaptive management,  
10 meaning that they don't necessarily have to  
11 completely comply immediately if they move in that  
12 direction.

13 CHAIRPERSON GEESMAN: Thank you.

14 MR. TRASK: Thanks, Noel.

15 One area that we're also considering in  
16 our analysis is, is the issue of environmental  
17 justice. Is Dale here, Dale Edwards? Okay.  
18 Basically -- oh, he is here. I'll have Dale  
19 Edwards of our Sociological Unit speak to that  
20 briefly.

21 MR. EDWARDS: Good morning. I'll just  
22 close this out, perhaps.

23 Just speaking very briefly about  
24 environmental justice as it relates to the aging  
25 power plants, as it kind of relates to the land

1 uses that we were talking about earlier, but it  
2 does come down to, as we describe here, the fair  
3 treatment of people of all races, cultures and  
4 income. And what we're going to be doing as  
5 relates to the, the study that we're doing, this  
6 chart up here describes demographics of the  
7 population within two miles, but at our last  
8 meeting we discussed that two miles is not what we  
9 typically do. We typically look at six mile  
10 radius around power plants when we're describing  
11 what the demographic, demographic characteristics  
12 are of that population.

13 And we will continue with that in this  
14 analysis, as well. That's not saying that there's  
15 an impact on people within six miles, it's just  
16 saying we want to know what is the demographic  
17 make-up. And other than that, we'll be thinking  
18 about what the possible effects on that  
19 population, whatever the distance is, as it  
20 relates to aging power plants, much similarly as  
21 we do with new power plant projects that we are  
22 analyzing.

23 And that kind of covers the point.  
24 That's really all we wanted to say about it.

25 MR. TRASK: Thanks, Dale.

1           The only thing else that we wanted to  
2 talk about this morning, as far as the Energy  
3 Commission staff, is where do we go from here to,  
4 to complete the aging power plant study.

5           Right now we're in the process of  
6 receiving responses from the generators and from  
7 the ISO, from specific information requests that  
8 we've given them. Basically, we're trying to put  
9 ourselves in their shoes. We're trying to -- into  
10 the generators' shoes -- we're trying to look at  
11 all the costs and all the income that they look  
12 at, all the possible policies, projects,  
13 practices, plans that are out there that could  
14 affect the economics of these units, and therefore  
15 their decisions of whether or not to retire.

16          As I mentioned earlier, we're looking  
17 very much at anything that could possibly change  
18 the RMR status of any of these aging units, which  
19 would primarily be new plant construction or  
20 transmission line projects and upgrades. We're  
21 going to classify the 50 units that we've whittled  
22 our list down to from the 66, of whether or not  
23 they're at the high, medium, or low risk of  
24 retirement. The 50 units are, are the generator,  
25 or the merchant generators that are in our list,

1       since we've assumed that the municipal utilities  
2       will not be retiring.

3               We are in the process of conducting our  
4       analysis of system-wide and local reliability  
5       effects. One of the things that we're doing there  
6       is going to be very clearly defining our terms  
7       with a glossary, but essentially we are now using  
8       pretty much the same definitions for local  
9       reliability as, as the ISO, and looking at the  
10      same local reliability regions that they look at.

11             We are conducting a transmission  
12      modeling effort to look at the effects of  
13      retirements, specifically as it, or especially as  
14      it relates to congestion relief in the Los Angeles  
15      Basin. Outside of the L.A. Basin, the analysis  
16      is, is relatively simpler and more  
17      straightforward, and, in fact, generally a  
18      relative simple supply and demand balancing is  
19      sufficient in those areas.

20             We will be completing our analysis of  
21      environmental and resource effects of the  
22      continued generation. And one thing I wanted to  
23      add there on the air quality investigation is that  
24      we are very carefully looking at the possible  
25      alternatives to these aging units. One thing that

1 we're realizing is that if you did want to set a  
2 goal of retiring these aging units as a means of  
3 improving air quality, that you'd have to be  
4 extremely careful about how you would craft that  
5 policy because you could, quite frankly, end up  
6 worse off if, for instance, you shifted all that  
7 generation to peakers rather than these boiler  
8 units.

9 We will be continuing to meet with the  
10 generators and with the agencies to hear feedback  
11 on our study process and results. One thing that  
12 I didn't mention earlier is that we have been in  
13 contact with most of the resource agencies  
14 involved with these power plants, the Fish and  
15 Wildlife Service, National Marine Fishery Service,  
16 Coastal Commission, BCDC, agencies like that, to  
17 get their input and also to hear feedback on our  
18 study process.

19 We are planning at least one additional  
20 workshop, possibly two, in this process, the aging  
21 power plant study process. Perhaps they might be  
22 combined with other study topics under the 2004  
23 update. But we are aiming at producing a draft  
24 study in July, and leading up to final adoption  
25 and sending it to the Governor in November.

1           CHAIRPERSON GEESMAN: Let's focus on  
2           your last chart there, if you can, the possibly  
3           another workshop. Under what set of circumstances  
4           would we not have a workshop on your draft report?

5           MR. TRASK: The only thing I changed as  
6           far as we talked last time, was the fact that this  
7           workshop was held as a, as an extension of our  
8           previous workshop. Essentially, we had a repeat  
9           of our May 18th workshop.

10          CHAIRPERSON GEESMAN: Yeah.

11          MR. TRASK: We, we're certainly open to  
12          direction from the committee on that one.

13          CHAIRPERSON GEESMAN: Yeah. Let me  
14          assure all of the participants that we'll have a  
15          workshop on the draft report. It'll be a  
16          necessary pre-condition of making the draft staff  
17          report ultimately a committee report, with  
18          whatever modifications the committee, based on  
19          stakeholder input, chooses to make, and then we'll  
20          probably hold workshops or hearings on the  
21          committee product before the full Commission  
22          adopts it.

23          MR. TRASK: Right.

24          CHAIRPERSON GEESMAN: But I want to make  
25          certain that all of the parties or stakeholders or

1 interested groups, however you characterize  
2 yourself, feel that you've got ample opportunity  
3 to make your views known, and that the assumptions  
4 and methodologies and conclusions that our staff  
5 and the committee, and ultimately the Commission,  
6 rely upon are fully vetted.

7 MR. TRASK: Very good.

8 We had scheduled here to have additional  
9 presentations, and we do have one lined up from  
10 the ISO on the RMR process which we'll go forward  
11 with. We had another one planned by Reliant, but  
12 the person who has that presentation, his plane  
13 was forced to land, it was an emergency landing  
14 this morning, so he, he is delayed and may not be  
15 able to give the presentation until about 3:00  
16 o'clock or so.

17 CHAIRPERSON GEESMAN: Okay.

18 MR. TRASK: So with that, I'd like to go  
19 ahead and turn it over to Catalin Micsa, of the  
20 ISO.

21 MR. MICSA: Hi, everybody.  
22 Commissioners, my name is Catalin Micsa, and I'm  
23 in grid planning for the California ISO, and I was  
24 planning to give you a presentation about the  
25 existing RMR process, criteria and methodology, or

1 may respond to any other questions that you may  
2 have regarding to existing RMR.

3 The RMR contracts are needed to maintain  
4 system reliability and also provides a good  
5 mechanism for the California ratepayers to get the  
6 necessary reliability, and also to meet the market  
7 power issue at a reasonable cost. May I remind  
8 you that all, all the RMR contracts are cost-  
9 based, so this is to prevent local market power  
10 approval for --

11 CHAIRPERSON GEESMAN: Well, when you  
12 speak of reliability, you're applying WCC and NERC  
13 criteria?

14 MR. MICSA: We are applying, when we  
15 designate the units, we are applying a subset of  
16 the NERC and WCC. At the beginning the, the ISO  
17 has applied the full set of criteria.  
18 Unfortunately, that requires every unit in the  
19 state to be RMR. And that was something that was  
20 not envisioned because if, if you do that, then  
21 there is no markets left. So we had to strike a  
22 balance between, you know, how much units would be  
23 under RMR to maintain reliability, and how much  
24 should be billed to markets. So the more -- and,  
25 and all the stakeholders went through a process

1       where they kind of looked at, you know, how much  
2       -- really, the RMR is more like a, like an  
3       insurance policy to make sure that the generators  
4       are there when they're needed for reliability. So  
5       how, how much insurance you want to buy for, for  
6       this product, and then the subset that come up,  
7       I'm going to have it in a few slides, it's  
8       actually only single contingencies.

9               CHAIRPERSON GEESMAN: And that, that  
10       methodology was approved by FERC?

11              MR. MICSA: That methodology was  
12       approved by the board.

13              CHAIRPERSON GEESMAN: Okay. And then  
14       ultimately, was it embodied in one of your tariff  
15       amendments submitted to FERC?

16              MR. MICSA: I don't think FERC required  
17       to know the criteria. FERC, FERC has approved the  
18       contracts and the, the methodology to sign the  
19       contracts, and every contract is actually filed at  
20       FERC and is based on the RMR criteria. I, I don't  
21       believe the criteria itself was approved by the  
22       board, but I'm not sure it, it needed to be filed  
23       with FERC.

24              CHAIRPERSON GEESMAN: Okay. And then  
25       when you speak of the market power issues, are

1       there clearly identified criteria that allow you  
2       to do that analysis, or is that more a judgment  
3       call?

4               MR. MICSA:  It was a judgment call.

5               CHAIRPERSON GEESMAN:  Okay.

6               MR. MICSA:  For, for local market power.

7               CHAIRPERSON GEESMAN:  Okay.

8               MR. MICSA:  So what the RMR studies  
9       really do is come up with the minimum market  
10      generation needed in megawatts in a certain area,  
11      in order to reliability serve the load.  And, and  
12      there are a lot of words here that, that require  
13      maybe some explanation.

14              When we talk about reliability, we talk  
15      about the subset of the grid planning criteria,  
16      which is it's only the single contingencies.  When  
17      we talk about local area, it's something that the  
18      board, our board has struggled with, too.  And  
19      they were trying to, to strike a balance between  
20      what is it local and what is it system need.  They  
21      went through and they said okay, well, we stop at  
22      mitigating 500 kV paths because there are a lot of  
23      units and a lot of owners that can mitigate that;  
24      therefore, there is a lot of competition and, and  
25      the markets will be driving mitigating 500 kV path

1 loads.

2 We are doing every single contingency,  
3 including single 500 kV lines, and 500 230 kV  
4 transformers. And, and we are signing RMR for  
5 those, but not to maintain a 500 kV path loads.

6 CHAIRPERSON GEESMAN: So how many local  
7 areas are there?

8 MR. MICSA: For 2004 there will be nine.

9 CHAIRPERSON GEESMAN: Okay.

10 MR. MICSA: For 2003, I think, I believe  
11 they're eleven.

12 CHAIRPERSON GEESMAN: Right.

13 MR. MICSA: Second step, when I'm saying  
14 market generation here that may require some  
15 explanation here, too, is that we look at every  
16 unit that has a participating generator agreement  
17 with the ISO, other than nuclear. Nuclears are  
18 considered to be online. QFs are also, Qualifying  
19 Facilities are also considered to be online at all  
20 times, and most of them don't have a PJ with the  
21 ISO. They are basically between themselves and  
22 the investor-owned utilities. So that market  
23 generation actually includes the muni generation.  
24 Okay.

25 Then we go, we go through the study and

1 we find out all the units that are effective and  
2 they're each effectiveness factor, and then, and  
3 then we publish the report.

4 CHAIRPERSON GEESMAN: Now, when you  
5 speak of the muni generation, you're, you're  
6 speaking of the munis that are part of your  
7 control area?

8 MR. MICSA: Yes. We speak about every  
9 unit generation that is in the ISO control area,  
10 correct, not the ones that are inside SMUD or  
11 LADWP's control.

12 CHAIRPERSON GEESMAN: Okay.

13 MR. MICSA: So first the RMR study, we,  
14 we go through, we find all defective units,  
15 including the munis, then we go to a screening  
16 analysis that was also approved by our board,  
17 where we publish an eligibility list which  
18 actually all the munis are taken out because we  
19 consider they have their own revenue and they have  
20 to serve native load. Most of them actually have  
21 a bilateral agreement with their own utilities  
22 where they help each other in case of emergency  
23 need.

24 Then we go through a large process where  
25 we, we put these needs up for bid. So the

1 existing generators, or any new generation or any  
2 demand side management, or the transmission owners  
3 can propose additional transmission projects to  
4 mitigate the needs that we have. And then we go  
5 through an economic analysis, and at the end we  
6 com up with a designation list.

7 So here's the RMR criteria that I was  
8 talking about. We only look at single  
9 contingencies, single unit transmission line  
10 outage, transformer line outage. And under the  
11 California ISO agreed planning criteria, a  
12 generator out followed by a line outage is also  
13 considered a single, single contingency.

14 These are all the studies that we  
15 perform. Power flow, post transient, and  
16 stability, to come up with the requirements.

17 A study methodology, we develop the  
18 accurate base cases with all the stakeholder  
19 inputs. We have stakeholder meetings before we  
20 start the studies, then we, we go do the studies,  
21 then we come up and we present all the results  
22 including unit effectiveness and eligibility  
23 lists, and all that. And then we go through an  
24 RFP process which has already went out for 2005.

25 CHAIRPERSON GEESMAN: And you repeat

1       that stakeholder process each year?

2               MR. MICSA: We repeat the stakeholder  
3 process each year. We can talk about it maybe at  
4 the end a little bit.

5               Here's a screening analysis I was  
6 talking about. Basically, the state, federal and  
7 municipal units are screened out. Units less than  
8 10 megawatts are screened out just because it's  
9 too cumbersome for the ISO to maintain so many  
10 contracts. And also, their reliability needs for  
11 such a small area, ten, ten megawatts, it's way  
12 too much work to deal with. And also, units under  
13 some specific long-term contracts that DWR has,  
14 they have already passed them on to the utilities.  
15 Some of them may be screened out.

16              CHAIRPERSON GEESMAN: Have any of the  
17 units in your, your top bullet there ever  
18 expressed an interest in bidding in one of your  
19 solicitations?

20              MR. MICSA: Actually, we have RMR  
21 contracts with NCPA. They were the only muni that  
22 basically proved to us that they do not have a  
23 standby agreement with the TOs where they help if,  
24 if there is any emergencies on the investor-owned  
25 utility transmission system, they're under no

1 obligations to help them out. Also, they prove to  
2 us that they, they don't have to run that  
3 generation to serve their load, as well. So then  
4 we give them an RMR contract. They ask for it,  
5 and we give it to them based on the need, the  
6 local area need.

7 CHAIRPERSON GEESMAN: But you, you've  
8 had no similar conversations with the City of Los  
9 Angeles, for example?

10 MR. MICSA: No.

11 CHAIRPERSON GEESMAN: Okay.

12 MR. MICSA: Actually, City of Los  
13 Angeles does, does not own any units inside ISO  
14 control area. They have their own control area.  
15 But some, some of the munis do, even though they  
16 have their own control area, like SMUD has its own  
17 control area but they have some other units that  
18 are under the ISO control grid, we just basically  
19 ship the power through California ISO control grid  
20 to their territory.

21 Basically the same thing you were  
22 talking about, units less than 10 megawatts.  
23 Units under specific long-term contract, if the  
24 unit, if the contract is unit specific and it's  
25 for the season in times that we need it, and they

1 have all the dispatch rights, the real time  
2 dispatch rights, then we will exclude those units.  
3 If not, we will sign them but the contract -- see,  
4 all the RMR contracts basically the ratepayers  
5 only pay for a, a portion of the fixed cost. So  
6 for some of the units that sign long-term  
7 contracts we know what their revenue requirement  
8 is. We know how much money they're getting from  
9 the long-term contracts. So really, the RMR  
10 contract is signed for a very, very small portion,  
11 what's left over there.

12 MS. JONES: Can we, can we go back just  
13 for a second.

14 MR. MICSA: Sure.

15 MS. JONES: When you're talking about  
16 the seasons and times of day that you look at  
17 these contracts for, when you go back and do your  
18 power flow studies and your other analytics to  
19 determine what your RMR requirements are, how many  
20 seasons and times of day do you look at? Is it  
21 for all seasons?

22 MR. MICSA: Well, we, we basically look  
23 for all season, yes. All season and all times of  
24 the day. I'll give you an example. Let's say a  
25 generator has a unit specific contract that was

1 signed by DWR, but it's only for, for summer peak.  
2 And if, if we need that unit in the spring or  
3 winter, let's say it's a winter peaking area, then  
4 we would sign them for RMR contract because we,  
5 our need is really in the winter, not, not in the  
6 summer peak time.

7 Or maybe they have a contract that's  
8 between 7:00 a.m. to 7:00 p.m., but we need it in  
9 the nighttime. So we, we go through this analysis  
10 and we try to figure out when exactly we need that  
11 unit, and if we need it outside of those hours  
12 that they were signed for by the long-term  
13 contracts, then we may sign them for an RMR  
14 contract as well, just so we can get a  
15 dispatchability rights during the, the times of  
16 need.

17 MS. JONES: Thank you.

18 MR. MICSA: You're welcome.

19 So then we go through the request for  
20 proposals. We give about, you know, 60 to 90 days  
21 for people to respond back, and then we evaluate  
22 all the proposals that we get and we, we get the  
23 most economic one, we get a proposal most economic  
24 one to the board. And that's the final  
25 designation. Basically, when, when we get the

1 proposals, since we already published  
2 effectiveness factor for every, every unit and  
3 relative effectiveness factors based on the most  
4 effective unit, and we will multiply their bids by  
5 the effectiveness factors, and we will rank the  
6 units and, and come up with the most economic way  
7 to take the units.

8           This is, this is how the process works  
9 today. We do, we have the same, we heard about  
10 the same concerns that you guys are trying to  
11 address here about the aging power plants. And we  
12 have opened a stakeholder process to try to see if  
13 there is any need to change the RMR criteria or  
14 designation process. One of the issues that, that  
15 came up was this 500 kV path mitigation, where  
16 even though there are a lot of units that, that  
17 are needed to mitigate something like that, and  
18 the board decided that is competitive, there are a  
19 lot of owners, a lot of generation, therefore you  
20 don't really need to go and sign an RMR contract.

21           So there is, there is no local area,  
22 there is no lower kV problem, but a lot of these  
23 power plants are needed to maintain 500 kV path  
24 load. What do we do if they're not there, because  
25 we, we have, you know, basically right now they're

1       called on must-offer, and unfortunately, I think  
2       the biggest problem here is that the must-offer  
3       does not have a capacity payment. If the must-  
4       offer would have a capacity payment factor into  
5       it, we would probably, probably be okay.

6               So we, we are going through that  
7       process. It's an open stakeholder process, and I  
8       believe CEC is part of that, and the CPUC and the  
9       EOP, they are all, they are all there. We already  
10      had the first stakeholder meeting and we will have  
11      a few follow-up stakeholder meetings to see if  
12      that criteria needs to be changed and how it needs  
13      to be changed, or maybe a different process needs  
14      to, we need to come up with, with a different  
15      process to account for those kind of operational  
16      issues that are not absolutely for local area  
17      need, but more or less for a wider area need.

18              Also, I think, you know, that resource  
19      adequacy will go a long ways if, if they can  
20      implement locational capacity needs.

21              CHAIRPERSON GEESMAN: Well, let's, let's  
22      talk timeframe. When do you envision your  
23      stakeholder process leading to results that you  
24      then take to your board?

25              MR. MICSA: We do not have a time set.

1 We, we were planning, I think the next stakeholder  
2 meeting would be probably beginning of July, and  
3 we'll have another one in September and October  
4 and, you know, we go on. One, one thing that come  
5 up of, of the stakeholder process was that if, if  
6 people could concentrate, see we opened it up for  
7 more than just the RMR criteria. We actually  
8 opened it up to see, you know, for issues related  
9 to capacity needs, to operational issues, to even  
10 consider if, if RMR is still required to stay on.

11 So when, when people focus on certain  
12 things that, that need to get done more faster  
13 than other things, then we can probably, you know,  
14 go and deal with those issues first, and maybe go  
15 and get board approval earlier for some things and  
16 just go deal with some other things a little  
17 later. There, there is no set timeframe. We, we  
18 were shooting for October or November of this  
19 year, though.

20 CHAIRPERSON GEESMAN: When do you  
21 envision your, your 2005 RMR solicitation to go  
22 out?

23 MR. MICSА: The 2005 RMR solicitation  
24 has gone out about two weeks ago. And the  
25 responses are due by July, middle of July, and

1       then we'll do the economic analysis in August. We  
2       have to have an approval from the ISO board of the  
3       new designations at the September board meeting,  
4       because the cancellation notices for the units  
5       that we do not need an RMR in '05 need to go out  
6       the first of October.

7               CHAIRPERSON GEESMAN: Okay.

8               MR. MICSА: However, if, if changes are  
9       welcome by stakeholders and we will change the  
10      criteria like September, October or November, and  
11      additional units may get signed up, that, that  
12      change can get done because we can, we can sign  
13      additional units. We just cannot cancel  
14      contracts. The cancellation of contracts needs to  
15      be done by the first of October. We can take  
16      additional units up to when the need arise, so if  
17      the need arise in next June or July we can take  
18      units all the way to next June or July.

19              CHAIRPERSON GEESMAN: Now, am I correct,  
20      then, in assuming that any changes in your RMR  
21      methodology would then take effect for the 2006  
22      contracts, not the 2005?

23              MR. MICSА: We were, we were shooting  
24      for the 2006. Now, if there are something obvious  
25      that everybody, you know, or more or less most of

1 the stakeholders agree that absolutely needs to go  
2 in '05, we will make that change and get it into  
3 '05. We will go with a separate package to the  
4 board and tell them this is one thing that we need  
5 to change right now, and the other stuff will come  
6 a little later for you.

7 CHAIRPERSON GEESMAN: Okay. But at  
8 least in terms of the way you've conducted the  
9 2005 solicitation, it's under the existing  
10 methodology.

11 MR. MICSA: That, that is correct.  
12 Because first we need to get the stakeholders to  
13 fastly agree on something, and then we need to get  
14 board approval. And that will take some time, and  
15 we didn't want it to hold the whole process back.

16 CHAIRPERSON GEESMAN: And for 2005, you  
17 are using nine local area reliability, or local  
18 reliability areas?

19 MR. MICSA: There, three are nine. The  
20 way they are defined today, there are nine  
21 existing.

22 CHAIRPERSON GEESMAN: Okay.

23 MR. MICSA: And two of them were  
24 eliminated based on additional transmission  
25 projects.

1           CHAIRPERSON GEESMAN: Sure. Well, I  
2           would say that from our standpoint, I think we  
3           want to make certain that we stay up to speed on  
4           the status of your process, and as you indicated,  
5           we are involved in that stakeholder process, and  
6           then that we accurately describe it in any report  
7           that we issue this fall.

8           MR. MICSA: And we're, you know, we  
9           fully work with you towards that goal.

10          CHAIRPERSON GEESMAN: Any questions from  
11          -- any questions from the audience?

12          I guess I'd like to now, if this is the  
13          appropriate time, ask for a bit of an update on  
14          Etiwanda.

15          MR. MICSA: Sure. Last year when we,  
16          when we went to the board, last year in July we  
17          have received, we had an eastern area need in the  
18          L.A. Basin. It was for 555 megawatts. And we  
19          have received transmission projects from Edison to  
20          solve the reliability need, and we also have  
21          received bids from Etiwanda to receive an RMR  
22          contract. During our economic analysis came out  
23          that the transmission projects were more economic.  
24          So the board has approved the transmission  
25          projects, not, not the generation.

1           It occurred to us in October, November  
2   of last year that Etiwanda was going to be  
3   mothballed. And we went back to Edison and  
4   basically asked for, for them to renew their  
5   commitment to get the projects done, because we  
6   may not have a backup alternative.

7           At that point in time, we have, you  
8   know, letters from Edison that told us yes, the  
9   bank will be there on time, they were two projects  
10   that were approved, basically was a new Mira Loma  
11   bank, and reconductoring of Mira Loma to Etiwanda.  
12   Really the biggest need was for, for the line, for  
13   the line it was bigger than the transformer. It  
14   was a commitment or the bank and also the  
15   reconductoring, they had some doubts about the  
16   reconductoring due to a butterfly habitat.  
17   However, they have told us they have secured 135  
18   percent emergency rating on the line that we could  
19   use for this summer.

20           Usually, Edison uses 135 percent only  
21   for double line outages, and they say we could use  
22   that double line outage rating that they have for  
23   single line outage, because they can take a high  
24   risk of needing the conductor, because they will  
25   replace the conductor anyway. The conductor needs

1 to come off, therefore they can take a high risk  
2 on the conductor, so they would give us the higher  
3 emergency rating.

4 So once we have received those papers  
5 from, from Edison, we send a letter back to  
6 Etiwanda telling them we are still going with the  
7 most economic one. And it just, it just occurred  
8 to us this last month that Mira Loma bank will be  
9 late by a month. However, Edison promise to  
10 change the ratings in the register has not  
11 materialized. And digging a little more deeper  
12 into the rating of the line it occurred to us that  
13 the line was not, the conductor was not the only  
14 problem for the line. They had line clearance  
15 problems, they had terminal equipment problems.  
16 And we have asked Edison for, for a new update.  
17 We haven't received anything back yet, but it  
18 seems like they may not have taken the additional  
19 steps of looking at the clearance problems, maybe  
20 raising some towers. Even though they don't  
21 reconductor the line, they go in and raise some  
22 towers and they need to change terminal equipment.

23 Since they haven't done that, we will  
24 not be able to receive 135 percent emergency  
25 ratings. Therefore, the two units are needed for

1 local reliability need, and they were actually  
2 approved by the board last year as a, as a backup  
3 to the transmission projects in case the  
4 transmission projects don't get done.

5 Based on -- there was another, another  
6 small issue here, where we didn't really waited  
7 all the way for Edison to confirm or non-confirm.  
8 The, the May 3rd issue with higher load forecast  
9 that we have seen in the system, we have done a  
10 temperature adjustment on, on the loads that we  
11 have seen on May 3rd, and it seems to us that the  
12 load will be higher between maybe 800, close to  
13 800 megawatts, at peak time. And --

14 CHAIRPERSON GEESMAN: Have you been  
15 doing any Edison --

16 MR. MICSA: In the Edison territory. So  
17 re-doing the, the analysis, we have find out that  
18 the overload have went beyond 135 percent anyway,  
19 that right now the, the load, the possible loading  
20 could be around 140 to 141 percent. Before it was  
21 around 133 percent. So even if Edison would be  
22 able to give us the, the higher emergency rating,  
23 which we have doubts for, we will still need the  
24 units to back up the line flows. So therefore,  
25 the additional steps were, were taken to assure

1       that Etiwanda could come back. And Edison peak is  
2       around September timeframe, and the first unit I  
3       believe can come on next month, and the second  
4       unit will be back around September timeframe.

5               CHAIRPERSON GEESMAN: Okay. Thank you.

6               MR. MICSA: Welcome.

7               MR. TRASK: Any questions for the ISO?

8               MR. MICSA: Thank you.

9               CHAIRPERSON GEESMAN: Great. Thanks  
10       very much.

11              MR. TRASK: We have a couple other  
12       people who have expressed a desire to do a  
13       presentation, but I'm proposing that we do that,  
14       one of them, AES, immediately after lunch, and  
15       then Reliant when the person gets here, probably  
16       around 3:00 o'clock.

17              CHAIRPERSON GEESMAN: Okay. Should we  
18       come back say at 1:15?

19              MR. TRASK: Sounds good.

20              CHAIRPERSON GEESMAN: Great. Thank you.

21              (Thereupon, the lunch recess was taken.)

## 1 AFTERNOON SESSION

2 MR. TRASK: Let's get going this  
3 afternoon with a presentation by AES. Following  
4 that we will start out panel discussions, and I'll  
5 put out a phone number for those of you listening  
6 in on the net and want to participate. You can  
7 call me and we'll patch you in.

8 MR. LEE: Good afternoon, ladies and  
9 gentlemen. I understand it's difficult to stay  
10 awake after lunch, so I'll try to be very brief.

11 My name is Vitaly Lee. I am the manager  
12 of commercial and regulatory affairs at AES  
13 Southland, and the owner of AES Alamitos, AES  
14 Huntington Beach, AES Redondo Beach. With me here  
15 I have my colleague, Steve Maghy, so if you do  
16 have questions both of us will try to, to answer,  
17 to address those.

18 What I wanted to talk today about  
19 briefly is AES in California addressed some of  
20 the market issues that had been previously  
21 addressed by my fellow generators in the last  
22 workshop, and then move to operational issues.

23 AES first came to California in '89,  
24 when we constructed AES Placerita in Newhall.  
25 Then in '98 we acquired three gas-fired stations

1 and those three stations are subject to this study  
2 of the CEC. In 2001 we acquired two biomass  
3 facilities. We added 450 megawatts in 2003 at  
4 Huntington Beach, Huntington Beach 3 and 4. We've  
5 installed state of the art emissions control  
6 equipment. We've had some capital projects.

7 I guess a small but significant  
8 difference from the previous generators is that  
9 all of our output is contracted out on a long-term  
10 to medium-term basis. And I just wanted to walk  
11 you briefly through the improved reliability  
12 availability and efficiency of the, of the three  
13 gas-fired stations that are subject to this study.

14 What you see here is a graph of the  
15 equivalent forced outage factor. And the pink  
16 bars are the Edison averages from '92 to '96 on  
17 those same units that we run today, and the blue  
18 is AES. And you will see that we have, through a  
19 concentrated effort, we have improved the  
20 reliability of the units that we operate, with the  
21 exception of Alamitos 1.

22 The next graph shows equivalent  
23 availability factor, and the difference between  
24 the previous metric. And this one is that the  
25 previous was determined by the service hours, and

1       this is determined by the period hours. And  
2       again, as you will see, that hour reliability has  
3       been improved. So I, I guess, in other words, we  
4       are proud of these aging units, and so.

5               CHAIRPERSON GEESMAN: When you say the  
6       period hours, what do you mean by that?

7               MR. LEE: You take service hours minus  
8       equivalent plant de-rates and divide that by the  
9       period hours at which you are looking.

10              CHAIRPERSON GEESMAN: Okay. So, so in  
11       the graph that you showed you were looking at a  
12       full year.

13              MR. LEE: Yes.

14              CHAIRPERSON GEESMAN: Am I correct?

15              MR. LEE: Yes.

16              CHAIRPERSON GEESMAN: Okay.

17              MR. LEE: Market policy issues --

18              CHAIRPERSON GEESMAN: Can I, can I ask  
19       you, before you go any further, in terms of the  
20       three plants that are within the scope of our  
21       study period, do any of those plants have  
22       contracts that would expire before 2008?

23              MR. LEE: No.

24              CHAIRPERSON GEESMAN: Okay. So they're  
25       fully contracted, then, for our entire study

1 period.

2 MR. LEE: That is correct. And beyond.  
3 And I guess the first bullet item addresses this.  
4 All of these units subject to the study are  
5 contracted out for the immediate future. But we  
6 agree with the previous statements by the other  
7 generators that the market signals and incentives  
8 must be in place to ensure adequate supplies going  
9 forward.

10 Resource adequacy requirements, capacity  
11 market L&P has all been, have all been addressed.  
12 We believe in healthy competition, and we believe  
13 that that will produce low prices, improved  
14 service, and give more choices to California  
15 customers.

16 And I guess I'll just keep -- on the  
17 operational issues, I don't know, has anybody else  
18 raised this? The deep cycling issue. Okay.

19 Well, this is one of our, I guess, major  
20 concerns that the mode that these units are being  
21 operated deteriorates the performance of the  
22 units. And basically, this mode results in  
23 significant increase and wear and tear, higher R&M  
24 costs, low efficiency, possible reduced  
25 availability, and terrible environmental

1 performance.

2 CHAIRPERSON GEESMAN: Now, do you see  
3 any difference in your older units and your, your  
4 new unit, Huntington Beach, in terms of the way  
5 they're operated?

6 MR. LEE: In the interest of accuracy,  
7 Commissioner Geesman, let me get back with you on  
8 this, because I, I know how the units that are  
9 under the Williams arrangements are operated. I'm  
10 not sure about 3 and 4, because I don't follow  
11 them on a day-to-day basis.

12 CHAIRPERSON GEESMAN: Yeah. My, my  
13 general question is the extent to which this  
14 particular load cycling regime is a permanent  
15 feature of California's restructure marketplace  
16 with our ISO. I certainly, certainly appreciate  
17 the point that you're making. I guess my, my  
18 underlying concern is that not anything that we  
19 can do that's likely to change that, it simply  
20 seems to be a feature of the way we dispatch  
21 plants now.

22 I'd certainly be, be open to any input  
23 that, that you or any of the other generators  
24 could provide to the contrary, because I, I do  
25 recognize that additional wear and tear that, that

1       this particular operating regime places on plants,  
2       I think it's true of both the new and the old  
3       plants. Obviously, the older plants are going to  
4       be the, the first casualties of that operational  
5       regime. But I don't, I don't see any likely way  
6       out of the particular practice that we're in.

7               MR. LEE: I understand, and I certainly  
8       agree with most of what you just said. I guess  
9       them the, the one example, and I wasn't at these  
10      plants before must-offer was introduced, but one  
11      example is the units being parked at the minimum  
12      load for the entire day on the rescinded waiver.  
13      And I guess all of us have been advocating the  
14      removal of must-offer --

15             CHAIRPERSON GEESMAN: Right.

16             MR. LEE: -- and ISO is moving in the  
17      direction of the flexible offer. And whatever the  
18      outcome of that will be, hopefully this will  
19      alleviate the problem a little bit.

20             And I guess my last slide. I promised  
21      this was a brief presentation. We agree in  
22      principle with the objectives and methodology  
23      proposed by the CEC staff. We participated in the  
24      study. We believe aging power plants continue to  
25      provide a valuable service. Competition and

1 adequate market structure are key. Our existing  
2 portfolio is contracted out, but we maintain  
3 interest in growing our portfolio, and I sincerely  
4 hope that the time and effort that goes into this  
5 study will benefit all of us.

6 CHAIRPERSON GEESMAN: Let me ask you if  
7 you see a trade-off potentially at risk if, if the  
8 state places more reliance on our existing  
9 generation fleet and creates either contract  
10 structures or, or various incentives to assure  
11 their continued operation, whether that's a trade-  
12 off against sending a clear market signal to  
13 encourage the construction of new plants.

14 MR. LEE: Well, I think this issue has  
15 been a little bit addressed, that most of these  
16 aging plants are located in certain, in certain  
17 locations. And with the upgrade in infrastructure  
18 I think there might be a need for new generation  
19 in other areas. And to that extent I don't see a  
20 conflict.

21 CHAIRPERSON GEESMAN: Thank you.

22 MR. TRASK: Okay. That's the last of  
23 our formal presentations, other than Reliant, when  
24 their person who's delayed gets here.

25 The schedule now calls for us for

1 breaking up into our discussion panels. Unless  
2 there's anybody who would like to provide any  
3 general comment at this point, this would be the  
4 time to come forward.

5 Very good. We are proposing to have our  
6 environmental discussion panel first. And I need  
7 to bring in one person by teleconference on that.  
8 Again, for anybody listening out there on the  
9 internet who would like to participate, if you  
10 could give me a call at 916/804-7271, and I'll  
11 repeat that in a little bit, about your interest  
12 in participating in any of these discussion  
13 panels, we're having one on policies, plans and  
14 practices that could affect aging plant economics.  
15 We're having another one scheduled for the role  
16 that these plants play in the system, and a final  
17 one on completing the aging plant study.

18 So with that, please, anyone who has an  
19 interest in participating in the environmental  
20 discussion panel, just come up to one of the  
21 chairs up here. And I'll get our caller in.

22 (Pause.)

23 MR. YORK: We seem to be missing some  
24 folks we thought would be here for the panel, so  
25 -- some staff people.

1 MR. TRASK: I'm having technical  
2 difficulties here. It worked fine just a moment  
3 ago, and now I can't -- oh, shoot. There we go.

4 SPEAKER: Environmental Health  
5 Coalition. This is Veronica.

6 MR. TRASK: Hi, Veronica. This is Matt  
7 Trask with the Energy Commission, calling for Al  
8 Wang.

9 SPEAKER: Your last name again, Matt?

10 MR. TRASK: Trask.

11 SPEAKER: One moment.

12 MR. WANG: Hello? Hello? Hello.

13 MR. TRASK: Hi, Al.

14 MR. WANG: Hey, how's it going?

15 MR. TRASK: It's Matt Trask.

16 All right. Well, we've developed a list  
17 of questions to help focus the discussion panel.  
18 But I think I'll just open it to general comment  
19 at first. Al, did you have any general comments  
20 to start with?

21 MR. WANG: I'll wait until everyone else  
22 has a chance to speak first, because I'm, I'm far  
23 away.

24 MR. TRASK: Very good. Any of our other  
25 participants like to make --

1 MR. WANG: Could you go around and just  
2 introduce who's there?

3 MR. TRASK: Oh, sure.

4 MR. HEMIG: Tim Hemig, with West, West  
5 Coast Power.

6 MR. MAGHY: Steve Maghy, with AES --

7 MR. TRASK: Could you hit the little  
8 button of the microphone, below that.

9 MR. MAGHY: Steve Maghy, with AES  
10 Southland.

11 MR. YORK: Rick York, Staff Biologist at  
12 the Energy Commission.

13 MR. LAYTON: Matt Layton, with the Air  
14 Unit, Energy Commission.

15 MR. TRASK: And I'm Matt Trask, Project  
16 Manager with the Aging Power Plant study, and I'm  
17 going to move over.

18 Okay. The first question on our list  
19 for this discussion panel is what other factors  
20 should the committee consider in the study of  
21 environmental and public health effects of the  
22 continued operation on aging generating units for  
23 RMR services and for peak needs. These include  
24 such topic areas of perhaps air quality, marine  
25 biology, land use, and others.

1 Any response or comment?

2 MR. HEMIG: Tim Hemig, with West Coast  
3 Power.

4 I did, you know, at the last meeting,  
5 presented our, our comments, so I just have one,  
6 one thing that we may want to consider. And  
7 that's when we talk about the cost of 316(b) and  
8 recognizing that there's an opportunity to  
9 evaluate and do studies over the next three and a  
10 half years as part of the regulation, that there's  
11 still substantial costs that will be borne by each  
12 of the facilities with once-through cooling  
13 systems in the three and a half year period the  
14 studies, the entrainment and impingement studies,  
15 the engineering analysis, some of those costs are  
16 very substantial. And on the order of two to \$3  
17 million worth of study costs. So there are still  
18 some substantial investments and compliance costs  
19 in that period of this, of this particular study.

20 And some of those costs for some  
21 facilities could be substantial enough to affect  
22 retirement decisions. And then when we consider  
23 RMR arrangements that we discussed today in  
24 detail, on a year-to-year basis, some of those  
25 costs, if this is an RMR facility that will need

1 to, to comply with 316(b), it's not sure if it's  
2 going to be able to continue to fund those studies  
3 that were initiated in that first or second year  
4 of the three and a half year period.

5 So one thing I think we need to include  
6 in the study is, is how that affects RMR and  
7 affects retirement decisions, the actual costs  
8 associated with 316(b) compliance.

9 CHAIRPERSON GEESMAN: Could you walk me  
10 back through the, the intersection of the 316(b)  
11 compliance studies and the RMR contract? I'm not  
12 clear on what you, what you just said.

13 MR. HEMIG: Okay. I guess where I'm  
14 hearing is if, for example, you initiate studies  
15 next year, you will, the two to \$3 million will be  
16 initiated at that point, and those will span over  
17 maybe a two to three and a half year period. If  
18 you're an RMR one year and then the next year  
19 you're not, and you're no longer able to recoup  
20 that, that, those compliance costs, then that  
21 might affect, if substantial enough, affect your  
22 ability to keep that facility operating.

23 CHAIRPERSON GEESMAN: And of these two  
24 and a half to \$3 million studies, am I to assume  
25 that that's evenly disbursed over time, or are

1       those front-end loaded or back-end loaded?

2               MR. HEMIG: I'd say most, the most  
3       substantial portion of that study is the  
4       entrainment and impingement study, which could be  
5       in one year.

6               CHAIRPERSON GEESMAN: Okay. And most  
7       likely the first year?

8               MR. HEMIG: Yeah, probably in the, the  
9       timeframe of the earlier part of the next three  
10      and a half years. Yes.

11              MR. WANG: So what is your comment  
12      regarding that again, that that should be a reason  
13      -- I mean, that should be taken into account in  
14      whether it's required to do the compliance  
15      studies?

16              CHAIRPERSON GEESMAN: No, I think what  
17      he's suggesting is that that could be a factor in  
18      the decision of whether or not to retire the  
19      plant.

20              MR. HEMIG: Okay. Okay. I mean, that,  
21      I had a similar comment regarding that issue, is  
22      like, is I can identify particular generating  
23      units where increased operation or an extension of  
24      the life span could unlock environmental impacts,  
25      and I think I, with RMR, with RMR, it's a great

1 example. I mean, for example, the power plant  
2 here is a once-through cool plant again, so  
3 they're doing that 316(a) and (b) as well. Which  
4 they're actually doing right now, or they just  
5 finished their studies.

6 And they'll bring up the same arguments.  
7 I mean, the, the water boards, like -- I mean, we  
8 have these new 316(b) rules, and we need to ensure  
9 compliance, and there's the possibility they may  
10 require additional technology for, for entrainment  
11 and impingement. And the argument, the same exact  
12 argument they're putting forth is that well,  
13 listen, if we're going to -- this plant in 2009,  
14 and RMR is a year by year evaluation, that may  
15 factor into the cost analysis.

16 But I think another issue to look into  
17 as well is, I mean, those should be the ones that  
18 are prioritized for retirement in the sense -- and  
19 I don't know if we're agreeing on this, but those  
20 are the ones that should be prioritized for  
21 retirement in the sense that they're cost  
22 prohibitive in the sense that the technology  
23 they're currently using has unwanted environmental  
24 impacts, and the cost of doing these studies  
25 without the assurance that the normal contract's

1 going to be there in the future.

2 Sort of a similar comment, but --

3 CHAIRPERSON GEESMAN: Well, I want, I  
4 want to reiterate that the Energy Commission's  
5 focus on, in this particular study ends in 2008,  
6 so we're trying to isolate potential threats of  
7 retirement between now and 2008. As I understand  
8 the comment, it relates to potential retrofit  
9 requirements --

10 MR. WANG: Yes.

11 CHAIRPERSON GEESMAN: -- that would  
12 probably not take effect until after 2008, but the  
13 study costs may be sufficiently large that you  
14 could come to a conclusion now, or certainly  
15 before 2008, that the plant simply ought to be  
16 retired because of the likely cost of the  
17 retrofit. I think I've got that, that correct.

18 MR. WANG: Yeah. My comment was a  
19 little more kind of, it's similar to that, but  
20 saying that I think what I'm seeing, at least I'm  
21 seeing in certain situations around the state,  
22 that's -- the argument that the cost associated  
23 with doing a retrofit potentially under 316(a) and  
24 (b), and the cost of doing the studies is often  
25 used as a reason not to do anything until that

1 plant is retired. And, and what I'm saying is  
2 that in that time, then when you say well, because  
3 it's cost prohibitive, we don't know, it's  
4 uncertain, then we, we're saddled with the  
5 environmental impacts as is, in the current time  
6 being until time the RMRs is decided to be  
7 removed.

8 Does that make sense?

9 CHAIRPERSON GEESMAN: I'm not certain I  
10 understand it, because I don't think under any set  
11 of circumstances are we anticipating that an  
12 actual retrofit would take place before 2008.

13 MR. WANG: I mean, I don't know if that,  
14 that's the case. For example, I mean, I mean, I,  
15 and again I'm talking about our plant, the Duke  
16 South Bay Power Plant down here in Chula Vista.  
17 They're currently, they're operating on an expired  
18 NPDES permit, for the water discharge.

19 CHAIRPERSON GEESMAN: Okay.

20 MR. WANG: They just concluded their  
21 studies, and the regional board is going to be  
22 issuing a new permit by August or September,  
23 probably later than that. And it's possible that  
24 they could require new discharge limits that would  
25 require some kind of retrofit in the plant in

1 order for them to comply.

2 CHAIRPERSON GEESMAN: And would those  
3 be, would those be new requirements under the old  
4 regs, or under the new regs?

5 MR. WANG: New regs.

6 CHAIRPERSON GEESMAN: Okay.

7 MR. WANG: Yeah.

8 CHAIRPERSON GEESMAN: You think they  
9 could move that quickly.

10 MR. WANG: Possibly. I mean, they were  
11 on schedule for them to release a tentative order  
12 in late July or early August. So -- and I, and I  
13 think, for example, one argument that, that was  
14 put forth in their study, in their 316(a) and (b)  
15 study, was well, A, it was on a plant, and, and  
16 it's uncertain in the future, and plus the lease  
17 of the plant itself for Duke to operate expires in  
18 2009, for example. I know that's somewhat of a  
19 different issue. But they're saying that those  
20 could be cost prohibitive reasons for them to do  
21 anything within that time.

22 CHAIRPERSON GEESMAN: Okay.

23 MR. WANG: Because RMRs on the plant, it  
24 has to, I mean, they can't, it can't be cost  
25 prohibitive for them to continue to operate the

1 plant, for example. So it's almost saying well,  
2 because of RMR we really can't do anything until  
3 the lease expires, essentially. Does that make --  
4 I know it's somewhat specific issue down here,  
5 but, I mean, it's somewhat related to a comment  
6 that was made.

7 CHAIRPERSON GEESMAN: Well, and we did  
8 have a pretty extensive discussion in our last  
9 workshop of the, the South Bay plant and the lease  
10 expiration, so I, I think we've got a pretty good  
11 record on, on the situation confronting the South  
12 Bay plant.

13 MR. WANG: Okay.

14 MR. HEMIG: And -- Tim Hemig -- brought  
15 this up because actually, for a little bit  
16 different purpose, is really just to say that  
17 there are some near term costs that are fairly  
18 substantial for certain facilities, and that the  
19 RMR arrangement may not be sufficient to, you  
20 know, basically fund those studies, and that maybe  
21 there's a potential for looking at how these  
22 things are, are paid for and how they're done in  
23 RMR arrangement, that maybe there, there's a  
24 commitment in financing or in funding these  
25 studies more in the long term, rather than the one

1 year to one year.

2 I think I -- I threw the idea out just  
3 if you, to include in the study, possibly, or  
4 CALISO's listening as a, you know, maybe something  
5 to be thought through.

6 MR. TRASK: Any other comments on our  
7 first question here, in general?

8 The second question that we have on our  
9 -- our --

10 MR. WANG: Well, I thought we were on  
11 air emissions, but we weren't really talking about  
12 air emissions. That was the first question,  
13 wasn't it?

14 MR. TRASK: It was actually just what  
15 other factors should we consider.

16 MR. WANG: Okay. I mean, I think  
17 another comment, and this was in our letter,  
18 actually, that we sent regarding the first,  
19 regarding the staff report earlier. I think it's  
20 called the, the staff briefing paper. Was in  
21 regards to the community plans for re-use -- I  
22 guess that does fit in land use section. Maybe  
23 I'll wait until we get there.

24 MR. TRASK: I think there was a question  
25 on land use. It still could be handled here, Al,

1 so go ahead.

2 MR. WANG: Well, I mean, I think the,  
3 the other issue, of course, is, for example,  
4 oftentimes we have aging plants that currently  
5 occupy land and there is an assumption by the  
6 community at large, for example, either through a  
7 master planning process, as we do at the South Bay  
8 Plant down here we have a master planning process,  
9 because it's on port property and city property,  
10 it's a city redevelopment area, as well. And in  
11 that master planning process, I mean, they're  
12 making plans to develop in and around the plant.  
13 They're making assumptions regarding move, the  
14 plant's going to be gone, it's not going to be  
15 gone, it's going to there. And development,  
16 they're making -- and there's actually a plant  
17 right now, it's going through an EIR process. And  
18 one, one of the scenarios that they're analyzing  
19 assumes there's no plant there.

20 And RMR does not, I mean, at least the  
21 -- I mean, the CEC process does not include, does  
22 not, does not plan for that possibility that the  
23 community has a plan to re-use the plant, and that  
24 kind of is independent from CALISO's RMR process,  
25 is what I'm trying to say.

1           So, I mean, they can make a  
2       determination that, okay, we're going to keep this  
3       thing RMR for XYZ amount of years. However, on  
4       the same tracking, through a master planning  
5       process or general plan process, the community is  
6       already planning to use that land for something  
7       else and assumes the plant's going to be retired.

8           MS. ALLEN: This is Eileen Allen, of the  
9       Commission staff. I supervise the land use unit  
10      in the environmental office.

11          I've made an effort to characterize the  
12      South Bay waterfront planning process that Chula  
13      Vista and the Port of San Diego are working on  
14      jointly as an ongoing process, with the future of  
15      the South Bay plant at the current site somewhat  
16      uncertain right now. How would you suggest that  
17      we characterize that process and the future of the  
18      plant different than how I have?

19          MR. WANG: Well, I mean, can you explain  
20      again how you have, again? I, I missed it, I kind  
21      of --

22          MS. ALLEN: I believe that I talked  
23      about the waterfront master plan process, and how  
24      it has, it has a ways to go before it's complete.  
25      It hasn't had a full set of hearings at the

1 community level, let alone any narrowing of  
2 scenarios regarding keep using the site, or, at  
3 the other end of the spectrum, abandon the current  
4 plant altogether. So --

5 MR. WANG: Like I said, the, the Port of  
6 San Diego and the city of Chula Vista just about  
7 two weeks, about three weeks ago approved two land  
8 use alternatives that are going for analysis under  
9 the, under CEQA.

10 MS. ALLEN: Yes.

11 MR. WANG: And both of those contemplate  
12 no plant.

13 MS. ALLEN: Okay. Thank --

14 MR. WANG: Or a, both of them say no  
15 plant and one of them contemplates a relocation to  
16 another site on, on the property.

17 MS. ALLEN: On the property.

18 MR. WANG: Yeah. So further south, up  
19 in the south, south end of the site. So, I mean,  
20 I guess what I'm trying to say, I mean, there is  
21 no, for example, if by that point where these  
22 plans are, let's say they choose one of those two  
23 alternatives, right, both of them assume there's  
24 no plant there and they start moving forward. I  
25 mean, the development plans are based on the fact

1       that -- assumption that there's going to be no  
2       plant there. But how does that track with the RMR  
3       process, I guess I'm trying to -- yeah.

4               MS. ALLEN: I see what you mean. It's  
5       been about two and a half weeks since we talked  
6       with the port staff, so I appreciate you bringing  
7       us up to date on the latest scenarios.

8               MR. WANG: I guess it's more of a  
9       communication issue then, I guess is what it  
10      sounds like.

11              MS. ALLEN: Timing, too. So this is a  
12      helpful reminder for us to get back in touch with  
13      the port staff and the city of Chula Vista.

14              I'm, I'm still trying to fathom the  
15      connection that you're looking for between the RMR  
16      process and what's happening at the local level as  
17      far as the waterfront master plan. If, if they  
18      were to build a new plant on the South Bay  
19      property, are you thinking that then --

20              MR. WANG: That would take RMR --

21              MS. ALLEN: Yes.

22              MR. WANG: Well, I -- no -- I mean, you  
23      can't predict these things, essentially. I mean,  
24      and, I mean, depending on who you talk to, some  
25      people think yes, some people think no. And, and

1       there's been no, no application submitted to the  
2       CEC for a new plant yet. So, I mean, if that were  
3       to happen --

4               MS. ALLEN: Yes.

5               MR. WANG: -- it has to happen, that  
6       application's got to go in soon, and -- I mean  
7       that construction's got to happen soon, as well.  
8       I think they all assume that after the lease state  
9       expires, and that's what we're talking, I think  
10      Matt mentioned that earlier about we did talk  
11      specifically about that plant and how there's also  
12      a lease that expires --

13              MS. ALLEN: Twenty-ten.

14              MR. WANG: Twenty -- 2009.

15              MS. ALLEN: Okay.

16              MR. WANG: And there's an assumption  
17      that after that RMR will be gone and that plant  
18      will be gone, too. I guess that's what, that's  
19      what I'm trying to say, that, you know, how do we  
20      -- how do we take these, how do these two separate  
21      processes meet together and, and have overlap. I  
22      don't know the answer to that.

23              MS. ALLEN: Okay. I think I understand.

24              MR. TRASK: It's certainly a topic that  
25      we are studying as part of the study, is anything

1       that can affect the RMR status of any of the  
2       units. We do know in the San Diego area that we  
3       have two power plants coming up online there, and  
4       a transmission project --

5               MR. WANG: San Miguel, yeah.

6               MR. TRASK: Right, that if all three of  
7       those things happen certainly it's reasonable to  
8       assume that the RMR status would likely change for  
9       some, if not all of the units there.

10              MR. WANG: Exactly. But, I mean, and I  
11       would also agree that we can't predict these  
12       things, either. But --

13              MR. TRASK: Right.

14              MS. ALLEN: I think our study will  
15       reflect how RMR is evaluated at least once a year,  
16       if not more frequently. And we, we need to keep  
17       up to date with that.

18              MR. WANG: I guess the recommendation  
19       would be now I'm trying to, I'm trying to think  
20       through this a little bit, would be, I mean, in  
21       the RMR annual with, it's called the -- the annual  
22       review, there should be -- because I know you only  
23       look ahead one, it's an annual one-year aspect, I  
24       mean, there should be an element in there that  
25       considers long term, what community re-use land

1 use plans are. And, and that should be an element  
2 that is looked at when looking into feasibility of  
3 RMR contracts being granted beyond the next year.  
4 Or that year.

5 MS. ALLEN: So the RMR designation  
6 process, as it shifts at least annually, should  
7 take into account the long term picture as far as  
8 community re-use plans?

9 MR. WANG: Exactly.

10 MS. ALLEN: Okay.

11 MR. WANG: Yeah. So, I mean, it's not  
12 looking at narrowly what's just ahead, one year  
13 ahead. It's looking beyond that, and taking into  
14 account, exactly. I mean, is that helpful?

15 MS. ALLEN: Yes.

16 MR. TRASK: Yes. The sensitivity  
17 studies that the utilities conduct leading up to,  
18 well, feeding into the RMR process, does consider  
19 five years out rather detailed, and then also  
20 looked at the tenth year out. I guess the  
21 recommendation would be to add the re-use land,  
22 land re-use issue in there. Yeah.

23 MR. TRASK: Okay, very good. Did you  
24 have any other comments on air quality there, Al?

25 MR. WANG: Yes. I mean, I think, this

1 was in my letter, as well. You know, you do know  
2 that the Cal EPA about six months ago, I think it  
3 was longer than that, did adopt environmental  
4 justice guidelines as far as -- that apply to all  
5 Cal EPA departments. And they're currently in the  
6 stage of implementation and coming up within each  
7 department within Cal EPA how they're going to  
8 accomplish those environmental justice guidelines.

9 And they include, they're pretty board  
10 sweeping in the sense they include a precautionary  
11 principle, cumulative impact analysis, what not.  
12 And as far as the CEC, I mean, all that I'm aware  
13 of is the CEC has a pretty narrow environmental  
14 justice kind of mandate and/or policy. And I  
15 guess as far as dealing with aging power plants, I  
16 mean, it should be a component in looking at  
17 whether -- as we look at the criteria of what  
18 you're looking at, whether to retire a plant and  
19 what the criteria you're looking at are,  
20 environmental justice should be an element that  
21 should be included in there.

22 Environmental justice is -- includes  
23 public health issues and also environmental  
24 issues, as well. It's a combination of both.  
25 And, I mean, I don't think -- I think you're both,

1 most of you here are probably aware of what  
2 environmental justice is. But I think the, the  
3 recommendations, I mean, like prior to development  
4 of newer technologies like dry cooling, plants are  
5 usually sited near coastal areas, and -- for  
6 cooling purposes, and those tend to be where  
7 there's commonly like dense populations. So, I  
8 mean, I think, I think, I mean, I think the  
9 question you made earlier that there be an  
10 environmental justice to the criteria in the study  
11 for identifying plants that are located near low  
12 income and people of color.

13 That was kind of convoluted, but did  
14 everyone get that?

15 MR. TRASK: Yeah. Yeah. Okay.

16 Well, we have three other questions  
17 under the discussion panel, the environmental  
18 discussion panel, and I can read through those and  
19 pause for comment after each one.

20 The second question was, what studies or  
21 other sources of information should the committee  
22 consider in the analysis of the environmental and  
23 public health effects of the continued operation  
24 of the aging generating units.

25 Any comments about other sources of

1 information?

2 MR. WANG: There, there was, there's  
3 been a number of studies done. I know there was a  
4 number done on Potrero and Hunter's Point in San  
5 Francisco, which I know are probably being slated  
6 to be retired, but there was a study done by  
7 Community for a Better Environment on the public  
8 health impacts, called, I think it was called  
9 "Power to the People". And that's something that  
10 should be looked at. I mean, they, they did a  
11 pretty close analysis of what the public health  
12 impacts are.

13 We did one down here called "Deadly  
14 Power" on the South Bay Power Plant. We did it  
15 with San Diego Bay Keeper, the Sierra Club, and  
16 the Audubon Society. And that outlines  
17 environmental and public health impacts of that  
18 particular plant, as well.

19 So, I mean, I think definitely the staff  
20 should have an opportunity to see both those  
21 reports.

22 MR. TRASK: I believe we do have that,  
23 Al, but just in case can you e-mail that to me?

24 MR. WANG: Certainly. Which one, the  
25 Communities for a Better Environment or the, the

1 San Diego one?

2 MR. TRASK: The Deadly Power.

3 MR. WANG: Okay.

4 MR. TRASK: Okay. Any other comments?

5 Third question. What are the likely  
6 effects on the environment and public health of  
7 the viable alternatives that could substitute for  
8 the lost generating capacity caused by the  
9 retirement of aging boiler units?

10 This kind of leads into one generator in  
11 particular has asserted that a new combined cycle  
12 plant may actually not be all that much better off  
13 than an aging unit, a boiler unit, as far as the  
14 aggregate heat rate and the emissions, considering  
15 the deep cycling that they generally do. But it  
16 also would have to do with what could possibly  
17 replace one of these units if they retired. A lot  
18 of people are assuming that perhaps the only thing  
19 that could be put into place in our time period,  
20 in 2008, would be a peaker unit, and that peakers  
21 in general have somewhat higher emissions than  
22 other units.

23 MR. WANG: That's a concern that we've  
24 had too, because, especially because they operate  
25 at peak demand, which is usually during the summer

1       when air quality is at its worse. But we're also  
2       seeing -- I know that down here in Chula Vista  
3       there is talk about Ranco building a peaker plant  
4       in down Chula Vista, and what we're seeing,  
5       though, is a lot of these peakers aren't actually,  
6       although they are being called peakers, if you  
7       look at what generation they're required over  
8       annual basis, they're almost like a mini-baseload  
9       plant. So that would be another thing to look at,  
10      as well. I mean, they're not actually operating  
11      as a peaker, they're operating as essentially  
12      intermediate baseload plant.

13               MR. TRASK: Yeah. If you could send us  
14      information on that, that would be good too, Al.

15               Any other comments on that?

16               MR. HEMIG: Yes. Tim Hemig here, again.

17               One thing I said at the last meeting,  
18      and I think it's worth repeating, is that there  
19      still should be a mechanism for, you know, showing  
20      that the redevelopment of the coastal power plants  
21      is a positive environmental change, and that -- I  
22      don't know how you are going to address it in the  
23      report -- but that there are net air quality  
24      benefits that would, would transpire from a  
25      redeveloped site, including, you know, emissions

1 on a kind of per megawatt hour basis because of  
2 the combined cycle aspect, versus the boilers.  
3 And really, just a more efficient use of the  
4 resources, the fuel, air, you know, air emissions,  
5 and cooling technology.

6 So I think that there's still benefits  
7 there that, when we talk about the existing sites,  
8 that redevelopment should be, you know, supported.

9 And secondly, when you do a comparison  
10 from the existing boilers to peakers, I think  
11 that's a good comparison. From what the  
12 information that's been presented, they do operate  
13 in a lot of respects the same way. And on  
14 emissions basis, they are actually better, in a  
15 lot of cases, on boiler facilities. I think it's  
16 a good comparison, especially when you also look  
17 at whether or not there's peakers to replace those  
18 if these boilers are shut down.

19 I mean, peakers aren't, aren't always  
20 very quickly to permit and build, either. So not  
21 only on an emission comparison, which, which is  
22 very good from, in fact, better on boilers to  
23 peakers, but also if these things really were  
24 retired, are you going to get peaking capacity  
25 built in that timeframe, or of that kind of

1 capacity.

2 Peakers are normally smaller, too, and  
3 these are large boilers. So I think that that's a  
4 good comparison, but also one that kind of is an  
5 eye-opener, that well, there isn't anything to  
6 replace these.

7 And really, the best thing in my mind to  
8 replace these is, is in a redeveloped or new  
9 equipment, modernized coastal power stations,  
10 because of the infrastructure that's there  
11 already. And really, one of the things I talked  
12 about in previous meetings here is the, the  
13 environmental comparison between, you know,  
14 redeveloping that site or going elsewhere to, to  
15 build a power plant somewhere else, away from the  
16 coast, there's the, the environmental impacts of  
17 that. And you can do the comparison on, you know,  
18 cooling technologies, what that does to the air  
19 emissions, what it does to using potable water  
20 sources or reclaimed water sources.

21 And I don't want to repeat all that, but  
22 it's, I brought that up, and it's probably in, in  
23 testimony or in our written comments, as well.

24 MR. WANG: Can I make a comment about --  
25 unless someone else has one first.

1 MR. TRASK: No, go ahead, Al.

2 MR. WANG: I mean, I do want to address  
3 that to a certain extent. I mean, first, on the  
4 reclaimed water and the dry cooling issue.

5 I mean, there -- reclaimed water, I  
6 mean, I think Palomar is probably the best kind of  
7 most recent case before the CEC, a permanent  
8 plant, that uses reclaimed water, and combined  
9 cycle, as well. I mean, a concern that we do have  
10 with wet cooling processes is that there is a  
11 plume that's created from using reclaimed, or just  
12 wet cooling, in general, cold cycle wet cooling,  
13 that does result in a net increase in PM10s.

14 Now, in the case of the Palomar plant it  
15 was located not directly -- again, in coastal  
16 areas you tend to have denser populations that can  
17 be, could be impacted, or could be downwind from  
18 the air emissions. And so that is an issue. I  
19 mean, if, if we intend to continue to develop  
20 coastal power plants, and I think at least  
21 Environmental Health Coalition and many groups in  
22 the region came out and opposed that, because  
23 we're saying well, if we're developing plants that  
24 aren't using water there's no need for them to be  
25 on the coast.

1           And I think, I mentioned before about  
2   what the community, the city of Chula Vista and  
3   port has been up to with redeveloping land. I  
4   mean, they'd rather redevelop coastal property  
5   without a power plant on it. This, this could be  
6   valuable property that could be worth more as  
7   redeveloped property than as a power generation  
8   facility. And I think Tim is correct, in the  
9   sense that one of the barriers to that is that the  
10   infrastructure is oftentimes there, transmission  
11   switchyard, that encourage the, the feasibility of  
12   building a replacement plant or, or a repower,  
13   what not, on site there.

14           But, I mean, I think that's, for  
15   example, what we're seeing down here is  
16   oftentimes, I mean, there's plans to within the  
17   master planning process I was talking before, the  
18   alternatives also contemplate moving the  
19   switchyards and undergrounding wires in order to  
20   improve the land for development purposes.

21           And so, and that's -- the second thing  
22   on dry cooling is that, I mean, yes, I mean, there  
23   is, I mean, I'm sure on testimony there's been  
24   issue regarding, I mean, the duct firing and the  
25   energy penalty, actually result in higher

1 emissions of, of particular, of air pollution  
2 coming from the plant. But again, when they're  
3 sites away from populations, like Otay Mesa, for  
4 example, is a site, is sited away from dense  
5 populations. I mean, the net impact on public  
6 health is, is less significant as when they're in  
7 densely populated coastal areas.

8 But I just wanted to respond to that.

9 CHAIRPERSON GEESMAN: Let me throw out.  
10 I think many of these land use questions are  
11 probably best thought of as site by site issues,  
12 and I, I'm not certain the benefit of, of our  
13 Commission trying to draw any generic conclusions  
14 about them. I was the Presiding Commissioner on  
15 the Palomar project, and that project involved, or  
16 enjoyed very strong local municipal support as a  
17 part of their economic development plans for the  
18 particular property involved.

19 And I recognize that's going to vary  
20 site by site by site. I think the environmental  
21 impacts are likely to vary site by site by site,  
22 and this Commission, confronted with a variety of  
23 different cooling alternatives for particular  
24 projects, has opted for dry cooling in some  
25 circumstances, reclaimed water in others, and the

1 use of once-through cooling in still others.

2 So I --

3 MR. WANG: Dry cooling only for one,  
4 though. Right?

5 CHAIRPERSON GEESMAN: Well, I think only  
6 one in San Diego County, but the Sutter project,  
7 if I'm not mistaken, involves dry cooling, as  
8 well.

9 MR. WANG: That's a cogen. Isn't that a  
10 cogen project, I think?

11 MS. ALLEN: No, it's a combined cycle.

12 MR. WANG: Okay.

13 CHAIRPERSON GEESMAN: So I, I guess I'd  
14 caution us away from, from too many generic  
15 observations, where, in fact, it's really a site  
16 specific issue that the project proponents are  
17 going to be in the best situation of, of really  
18 laying out what the benefits are.

19 MR. TRASK: Okay. Any other comments on  
20 this question?

21 MR. LAYTON: Matt, I have a comment.  
22 Tim had mentioned last time that he was concerned  
23 about the offsets and how they would be devalued  
24 by up to 90 percent. You know, that, that was  
25 assuming that you don't already have best

1 available control technologies on your existing  
2 facility. Since new facilities all have SCR, they  
3 wouldn't be devalued by 90 percent; they'd  
4 probably be transferred about one to one,  
5 especially if you stayed onsite. Same for PM10  
6 and same for SOx, because you're using the best  
7 available control technology already.

8 So from an air quality perspective, an  
9 air emissions perspective, we see the benefits as  
10 being very small, if, if at all, from replacing  
11 or, you know, retiring these aging power plants.

12 MR. HEMIG: Yeah, well, there's other  
13 discounts besides BACT discounts. There's  
14 discounts by operating days in a year, which can  
15 be 50 percent to 100 percent discount. So my, my  
16 point is that --

17 MR. LAYTON: Well, I'm not talking about  
18 the permit. I'm talking about actual emissions  
19 to, the new actual emissions. Again, it does  
20 involve some assumptions about what might happen,  
21 but the question is would emissions increase or  
22 decrease at that site. There's a possibility that  
23 emissions could increase from that site, or stay  
24 the same, even with a different facility operating  
25 on a more efficient level, you know, say fewer

1 pounds of emissions per megawatt hour, the local  
2 public is still going to see the same emissions.

3 So from an air quality perspective,  
4 since offsets are so tight, you're not going to  
5 see much change in this really small portion of  
6 the overall inventory.

7 MR. HEMIG: Well, rather than, you know,  
8 use up the time for this, just real quickly, what  
9 my point is, is there's short term and there's  
10 long term emissions. There's concentrations out  
11 of the stack. And my point was that there are  
12 improvements and net decreases in air quality air  
13 emissions from a redeveloped site on the, on the  
14 short term basis. If you talk about that the new  
15 unit will run more and you talk about mass  
16 emissions over the, a year, then that's, that's  
17 true.

18 But, I mean, you talk about what's  
19 coming out of the stack and how many, how much  
20 power you might be able to produce for those, that  
21 emission rate, there are improvements in a two on  
22 one combined cycle, or any kind of a combined  
23 cycle, obviously, with the additional generation  
24 produced for -- per, you know, unit of fuel  
25 combusted, and then, of course, per unit of

1 emission produced.

2           So, we've done that analysis, like at El  
3 Segundo, for example, and show that even though  
4 your annual emissions might end up being higher in  
5 some cases, what you'll see in the short term  
6 hourly, daily, which is what really is affecting  
7 air quality, is far, far improved, substantially  
8 improved, because of the combined cycle aspect.  
9 And that's the part I'd like to see included in,  
10 in the evaluation, is that redeveloped sites, you  
11 know, do have the benefits, and that's what I'm  
12 talking about, the benefits is the short term.

13           MR. LAYTON: Oh. We've, we've also seen  
14 that in taking down a large boiler stack and  
15 putting in a combined cycle shorter stack, impacts  
16 increase significantly in the near field. So we,  
17 I think you have to be really careful in assuming  
18 that because the emissions' profile, or the  
19 emissions' numbers change, the impacts actually  
20 decrease. The impacts may increase.

21           CHAIRPERSON GEESMAN: I really want to  
22 pursue this further as the staff writes up its  
23 report. Parts of it sound a little squishy to me,  
24 or a little bit apples and oranges, and I want to  
25 make certain that we frame the question likely to

1 be in front of policy makers in an accurate way.

2 You know, with a redeveloped project, I think  
3 you're looking at emissions over the life of that  
4 project, which, for the sake of argument, let's  
5 suggest is 30 years.

6 I'm not certain that anyone is  
7 suggesting that the continued operation of the  
8 existing facility would be reasonable over the  
9 same period of time, and I also am not certain how  
10 to weight the localized impact of emissions  
11 compared to the basin-wide impact of, of  
12 emissions. It strikes me that the Commission  
13 makes decisions on a much broader basis than  
14 simply those isolated to an extremely localized  
15 effects.

16 At least at this point, I'm not prepared  
17 to, to embrace the way you framed the question,  
18 Matt, but I, I want to look at it a lot more  
19 carefully as you guys write up your report.

20 MR. LAYTON: Okay.

21 MR. TRASK: One of the things that we  
22 are considering is a couple of sort of, I guess  
23 you'd say case studies, where we take an existing  
24 power plant and, and rather deeply analyze the  
25 potential alternatives to that plant, whether it's

1 new construction on the same site or shifting to  
2 another site, and see if we can delve deeply into  
3 those kind of issues.

4 CHAIRPERSON GEESMAN: And I, I also  
5 don't know that assuming today's operating profile  
6 is a good way to compare an existing plant with,  
7 with a redeveloped plant on the same site. I  
8 think I understand why we operate the plants the  
9 way we do now. I'm not at all convinced that  
10 given the opportunity to vote for that operating  
11 profile over the long term, that's the way I'd  
12 vote. It seems to me that we can take quite a bit  
13 more advantage of the combined cycle technology  
14 than the way we've been running these plants, at  
15 least the last several years.

16 MR. TRASK; That, that is one of the  
17 more interesting aspects of all this to myself,  
18 personally, and I, I would definitely like to hear  
19 a lot about that from the participants.

20 Moving on to the next question in the  
21 environmental discussion panel, and the last one.  
22 Are these -- are there opportunities for  
23 improvements in the environment or public health  
24 from increasing generation at an aging boiler  
25 unit, such as by displacing generation of peaking

1 plants, or by shifting generation from --  
2 generation away from air quality hot spots?

3 MR. WANG: Can I take a crack at this  
4 one?

5 MR. TRASK: Sure, Al.

6 MR. WANG: Again, I mean, I, I apologize  
7 to the Commissioner because I'm, I'm going to  
8 speak on a site specific basis again. But this is  
9 where my knowledge is, and it's where I can speak  
10 from.

11 I mean, regarding hot spots, I mean, for  
12 example, in the San Diego Air Pollution Control  
13 District monitoring station in Chula Vista, for  
14 the last five years has registered violations of  
15 the state air quality standards for PM10 and 2.5,  
16 which is the one we worry about the most, and  
17 quality standards for PM2.5. And, I mean, and I  
18 think the question is saying by shifting  
19 generation away from air quality hot spots, I  
20 mean, that's been a key issue in the community for  
21 residents living with, in downwind of the plant,  
22 is that they ask themselves, I mean, our air  
23 quality is already, I mean, yes, arguments are  
24 made if the majority of the, of the violations are  
25 due to vehicles, what not, not the baseload

1 generation. But when you add another baseload  
2 generation plant in a region, or repair one,  
3 you're ensuring, like, for example, in this case,  
4 South Bay Power plant, 1600 pounds a day, up to 16  
5 pounds a day of PM10.

6 So, I mean, I, I think there is kind of  
7 from a power perspective, if you seen an area  
8 where there is a hot spot, where there are  
9 violations of, in particular PMs, which we're  
10 worried about the most regarding public health,  
11 there should be a policy preference of locating  
12 them away in -- again, the great example would be  
13 the air quality for the Otay Mesa generating  
14 plant. I mean, that was located away from  
15 populated areas, away from hot spots, away from  
16 sensitive receptors. And that's really the key,  
17 is the sensitive receptor issue.

18 And the same applies to the peakers,  
19 because, again, as we said earlier, I mean, they,  
20 they do operate at peak demand times during the  
21 summer when air quality is at its worst, and they  
22 should be located away from sensitive receptors  
23 and from hot spots where they're -- for example,  
24 the, the Ramco plant is proposed in downtown Chula  
25 Vista, 500 feet away from an elementary school.

1           So, I mean, that, those are some of the  
2           kind of preferencing that we should be seeing in  
3           regards to shifting generation away from these  
4           kinds of locations.

5           MR. TRASK: All right. Well, that,  
6           that's all the questions that I had developed for  
7           this discussion panel. But I'll just throw the  
8           floor open right now to any other issues that  
9           anybody would like to discuss. Anybody in the  
10          audience, as well.

11          MR. WANG: I mean, I, I think this is  
12          not, this is -- it somewhat relates to this issue,  
13          though, because public health and environmental  
14          issues are such a community valued issue that they  
15          take a strong interest in. I mean, I definitely  
16          encourage that in the future some of these  
17          workshops be, be held in locations other than  
18          northern California. For example, perhaps the  
19          possibility of having one in southern California  
20          so community members that are interested in this  
21          can actually come and attend and give their input,  
22          as well.

23          MR. TRASK: Very good. Thanks, Al.  
24          We're probably going to hang up on you here,  
25          unless you want to add final thoughts.

1           MR. WANG: No, I think, I think I've  
2 taken up enough air time.

3           MR. TRASK: All right. Thanks very  
4 much.

5           MR. WANG: All right.

6           MR. TRASK: I can never figure out how  
7 to hang up the phone here. Well, I assume it'll  
8 hang up itself.

9           Our next scheduled panel is on the role  
10 that the aging power plants play in the system. I  
11 have a list of five questions on that.

12           Any interest from the audience in  
13 participating in the, the role that plants play?  
14 Actually, I would like to perhaps explore what  
15 Commissioner Geesman just brought up there, which  
16 is essentially the way the integrated system is  
17 operated, are there opportunities, could there be  
18 a policy crafted such that we could take more an  
19 advantage, I guess you could say essentially  
20 shifting back to the old environmental dispatch  
21 policies, where you would bring on units in order  
22 of their impact, with the least impact first and  
23 the highest impact last.

24           In a free market it's obviously a little  
25 more difficult to control. Of course, I guess

1       there's quite a bit of argument of whether we have  
2       a free market. But basically, I know you're,  
3       you're limited quite a bit with the nuclear  
4       plants. They, they essentially have to operate  
5       at, at baseload, and that doesn't leave a lot of  
6       generation at night for the combined cycles to  
7       come in and also operate at baseload. But I think  
8       we're, especially in the summertime where you have  
9       the air conditioning loads very low in the morning  
10      and very high in the afternoon, we're always going  
11      to have a lot of cycling one way or the other.

12               But I think that's a very interesting  
13      area of, of discussion, and I would welcome any  
14      comments on that.

15               Well, I'll go ahead and just read off  
16      the questions here. If anybody wants to, to  
17      provide input just come on up here, and if you're  
18      listening in on the internet, again, give me a  
19      call at 916/804-7271.

20               The first question in this discussion  
21      panel. What are the most important points to  
22      consider in the Aging Plant Study concerning the  
23      role that aging generation units play in the  
24      integrated electric and natural gas industries?

25               Should I go ahead and read all these

1 questions, or should we just skip on to the next  
2 panel?

3 CHAIRPERSON GEESMAN: Why don't you go  
4 ahead and see if you elicit a response.  
5 Otherwise, I --

6 MS. KAPLAN: I have some --

7 MR. TRASK: Okay.

8 MS. KAPLAN: And I think he's going to  
9 be here in a few minutes.

10 I'm Katie Kaplan with the Independent  
11 Energy Producers Association. I think it's really  
12 important as you're looking through this issue to  
13 consider the context that these units are being  
14 utilized now in the market. Currently, many of  
15 these units, especially the units that are in  
16 question here, are located in southern California  
17 along the coast. They do not have RMR contracts,  
18 and they're being utilized every day through the  
19 must-offer obligation that the ISO utilizes, you  
20 know, via FERC.

21 A couple of quick things just to point  
22 out. This is a much bigger issue than I think  
23 people realize. On an average, over the last 12  
24 months there was about 626,000 megawatt hours  
25 procured per month, and over \$100 million worth of

1 costs associated with the must-offer obligation in  
2 the south. And these units now are in a situation  
3 where they're very much struggling to get by,  
4 because they're being run at minimum load at the  
5 dirtiest, the worst times they can be run during  
6 the day, and they're just sitting there  
7 essentially idle as part of the must-offer  
8 obligation.

9 This problem will be exacerbated come  
10 the fall, when the ISO puts in a part of their  
11 market design that will take away a significant  
12 amount of compensation for these -- from these  
13 units that is currently contributing to the, some  
14 of the capacity payment, or capacity cost  
15 associated with the units. So I think it is  
16 really important, again, to look at what, you  
17 know, what happens now, what's happening now.

18 Out of these units that are being  
19 committed, 97 percent of them are in southern  
20 California. They're, two-thirds of that is being  
21 utilized for, quote, unquote, local reliability  
22 needs. Don't have RMR contracts. So obviously,  
23 the RMR criteria of the ISO is, is flawed. They  
24 are definitely working to, to amend that criteria.  
25 I just don't think that's going to happen in the

1 next couple of months, before the deadline to  
2 enter into new RMR contracts, which is in October.

3 In addition, the ISO has put out a paper  
4 indicating they're moving toward regional  
5 procurement of ancillary services, which will put  
6 even more strain on these units located in the  
7 south, in that 70 percent of the ancillary  
8 services are currently now procured in the north.  
9 IEP doesn't have a, a problem, necessarily, with  
10 the regional procurement. It's just it's  
11 something that this Commission should be aware of  
12 when they're considering the study.

13 We have a couple of solutions that we  
14 think would, would meet some of these challenges.  
15 In addition to participating at the ISO through  
16 their must-offer stakeholder process as well as in  
17 front of FERC, as well as participating in their  
18 RMR evaluation processes there, there are a couple  
19 of options that the ISO could utilize, and this  
20 Commission can utilize, when they're considering,  
21 you know, how to meet the needs, the long-term  
22 needs with these aging power plants until we can  
23 get some newer plants, some more efficient plants  
24 brought online to meet the needs for California.

25 One would be sort of a short-term

1 reliability contract. And this is a concept that  
2 I think Trent will discuss further when he gets  
3 here. But it essentially says that, you know, the  
4 current RMR contract is very limiting as far as  
5 what the ISO can use the plant for. And because  
6 none of these plants, or a significant amount of  
7 these plants don't have any bilateral contracts  
8 now, or won't, you know, come January 1st this  
9 year, you know, there are definitely more  
10 flexibility that I think that the ISO would need  
11 as far as, you know, what they could utilize these  
12 plants for.

13 We outlined, and I'll, and I'll leave a  
14 copy of it here, some of the, some ideas that we  
15 had as far as what these short-term reliability  
16 contracts would look like. But essentially, what  
17 they would do is they would fill the gap between  
18 now and when we get a viable resource adequacy  
19 requirement implemented in California. And it  
20 recognizes that, you know, this capacity is  
21 valuable, it needs to be compensated accordingly  
22 to the value that it provides to the grid, and on  
23 a long-term basis, you know, ideally these  
24 contracts should be entered into by the  
25 appropriate load-serving entities on the interim

1 basis. That's just not going to happen.

2 So, you know, we need to figure out a  
3 way that these units can be compensated for the  
4 services they provide so that they are there to  
5 meet the, the real time reliability needs of the  
6 grid from, you know, anywhere from tomorrow until  
7 2008.

8 CHAIRPERSON GEESMAN: Or 2006.

9 MS. KAPLAN: Or 2006. But even in the,  
10 even, let's just say in the most ideal  
11 circumstance, I think the ISO would have to be  
12 very comfortable that all of the local  
13 deliverability criteria have been established,  
14 that, you know, that these units, they would be  
15 comfortable if they didn't receive a resource  
16 adequacy contract, that they could just go offline  
17 and go away. And I don't think that they, you  
18 know, I don't think that that's the case.

19 I mean, the, even the most recent  
20 procurement papers that have come out, you know,  
21 don't necessarily address the local deliverability  
22 requirements in detail. And if the utilities don't  
23 have that direction that they can consider local  
24 deliverability when entering into contracts, you  
25 know, it makes it very difficult to evaluate an

1 older plant to, let's say, newer plant located,  
2 you know, 500 miles from the load center. I mean,  
3 it's just, they can't, you know, get cost recovery  
4 for it.

5 So unless you address that local  
6 deliverability issue, I think the ISO's still  
7 going to have to have a mechanism even after they  
8 get resource adequacy in. You know, we see these  
9 short-term reliability contracts as, as, you know,  
10 perhaps meeting that need.

11 CHAIRPERSON GEESMAN: And how, how would  
12 they be an improvement over the existing RMR  
13 contract?

14 MS. KAPLAN: I think that they could  
15 provide a lot more flexibility to the ISO.  
16 Meaning that right now the RMR contracts are very,  
17 very limited as to what they can be utilized for,  
18 quote, unquote, you know, only the local  
19 reliability needs unless they're in an emergency.  
20 We see these units as being, I mean, these  
21 contracts as being very flexible. And they, you  
22 know, they could provide ancillary services, they  
23 could provide, you know, what, you know, the  
24 different local reliability needs, system  
25 reliability needs, long-term reliability needs.

1           You know, I mean, I suppose it would be  
2           an augmentation to what the current RMR contracts  
3           provide.

4           CHAIRPERSON GEESMAN: But if there were  
5           a perceived need for those additional services,  
6           wouldn't it be more productive to simply alter the  
7           existing RMR contracts?

8           MS. KAPLAN: You would think so. But,  
9           you know, what we have learned as part of the  
10          process, we have -- start a process to modify this  
11          criteria when it came to light what the must-offer  
12          obligation was being utilized for, which was local  
13          reliability needs. All these units used to have  
14          RMR contracts, now they don't. You know, the  
15          must-offer obligation really replaced RMR in a lot  
16          of ways.

17          And the ISO has started that process. I  
18          just don't think it's going to, you know, it's  
19          May, or it's June, I guess, now, what day is it?  
20          It's June, and these contracts have to be signed  
21          by October. And you're talking about, you know,  
22          doing a massive overhaul of the RMR criteria. We  
23          have provided to the ISO, the ISO's own department  
24          of market analysis has done a significant amount  
25          of work with regard to when these units are being

1 utilized, what they're being utilized for, all the  
2 historical information is there. And they have  
3 not incorporated that into their current RMR  
4 criteria evaluation. So --

5 CHAIRPERSON GEESMAN: Well, why, why  
6 would, why do you think it would be easier to  
7 create a new instrument entirely, in contrast to  
8 the difficulty that you faced trying to expand the  
9 existing RMR criteria?

10 MS. KAPLAN: I think it would be easier  
11 because we have all of the historical information  
12 in one place. It's all at the ISO. We've  
13 articulated, you know, on -- I say we, you know,  
14 the stakeholder group that was working --

15 CHAIRPERSON GEESMAN: Yeah.

16 MS. KAPLAN: -- you know, they've  
17 articulated, you know, when these units are being  
18 used, why they're being used. The problem with  
19 the RMR is that, you know, unless you -- I mean, I  
20 guess it would be probably the same thing. You  
21 either do a massive overhaul of the current RMR,  
22 or you just come up with, you say hey, we need  
23 these local, we have this local need in southern  
24 California, we're going to go out for an RFP, this  
25 is the amount of megawatts that we need, it's kind

1 of like the summer peaking program that the ISO  
2 contemplated doing during 2001. It's something to  
3 augment the current RMR process.

4 CHAIRPERSON GEESMAN: Yeah, I'm just  
5 trying to determine is one easier to obtain than  
6 the other, and is your difficulty in, in  
7 persuading the ISO to alter its RMR criteria  
8 symptomatic of a, of a different kind of problem?  
9 And perhaps, perhaps we should turn to the ISO.  
10 We can --

11 MS. KAPLAN: Maybe he can, maybe they  
12 can answer the question.

13 MR. MICSA: I guess I'd, I'd like to  
14 answer a few, a few questions that were, that were  
15 raised here, is that the, the RMR contracts can be  
16 used for a lot of things. What, what really they  
17 meant here is that when we sign RMR contract it's  
18 very specific what we sign them for, only local  
19 reliability and not for maintaining 500 kV paths.  
20 There is a discrepancy, and everybody realize  
21 there is a discrepancy between so-called local  
22 area.

23 Under RMR methodology, what the board  
24 decided is that maintaining 500 kV path is not a  
25 local area, it's a system problem. When they get

1 this, when the generators get dispatch every day,  
2 at least it's an intra, interzonal problem.

3 Everything is tagged as being local, including  
4 mitigating 500 kV paths that are not inter-zonal.

5 So it, it, from the generator's perspective, I  
6 understand perfectly what you're saying, is they,  
7 they're getting a tag and saying you are called  
8 for local, for local every day. On the other  
9 hand, if you just look at what we are supposed to  
10 be signing them for for RMR, it's not the same  
11 local. It, it's a different local.

12 And we have opened the stakeholder  
13 process to, to deal with that issue. The ISO is  
14 not, doesn't have the authority to sign other  
15 contracts right now, other than RMR contract. So  
16 that's why it was probably easier to tag along  
17 with the, with the RMR criteria, and, and try to  
18 deal with the, this must-offer issue for 500 kV  
19 path mitigation, to go through the same process  
20 rather than trying to get, which we could go that  
21 way, too, we could ask the board to just give us  
22 authority to sign additional contracts that are  
23 not out of, more other type of contracts, other  
24 type of reliability contracts. That, that could  
25 be another route, too.

1           CHAIRPERSON GEESMAN: Yeah. I, I'm just  
2       inclined to think, based on my limited experience  
3       on your board, that probably opens more questions,  
4       Katie, than it, than it answers, and that you're,  
5       you're more apt to prove successful, I think,  
6       trying to, to amend or make use of the RMR  
7       structure rather than create a new instrument  
8       entirely.

9           I, I may be wrong on this, and I  
10      certainly haven't talked to, to any of the ISO  
11      board members about it, but I think you've got a  
12      pretty clear interest in timeliness, and are  
13      needing to, needing to address something that,  
14      that gives you the greatest assurance that you can  
15      get a timely resolution.

16           MS. KAPLAN: I'll take that into advice.  
17      I mean, we, we have attempted to do that, so --

18           CHAIRPERSON GEESMAN: You know, I, I  
19      understand you have.

20           MS. KAPLAN: And so, I mean, right now  
21      we do have this idea pending before FERC, as sort  
22      of a augmentation to the must-offer obligation.

23           CHAIRPERSON GEESMAN: Yeah. Now, you  
24      haven't gotten much traction before FERC thus far,  
25      have you?

1 MS. KAPLAN: We just put it before them  
2 last week, so --

3 CHAIRPERSON GEESMAN: Okay. But you  
4 previously raised concerns about --

5 MS. KAPLAN: Must-offer --

6 CHAIRPERSON GEESMAN: -- misuse of the,  
7 of the must-offer.

8 MS. KAPLAN: Right. Only, but this sort  
9 of replacement or, you know, all of the -- we only  
10 comprehensively put everything before FERC last  
11 week as a response to the ISO's must-offer filing.

12 I would just, another, another part of  
13 challenge, I suppose, that exists right now within  
14 the RMR criteria and why it becomes so  
15 problematic, is that they consider units to be  
16 online through the market, and this was a criteria  
17 that was established when the PX was in place, and  
18 so they assumed that all these units are online as  
19 part of the, quote, unquote, market mechanism.

20 Well, there is no market now. There is  
21 no day-ahead mechanism to commit units, you know,  
22 at all. And so now, when you, when you're sort  
23 of, you know, putting in all of these what I would  
24 call false assumptions into the study, you know,  
25 to say well, we're assuming all these market,

1       these units are going to be online even though  
2       they have no bilateral contract, they have no day-  
3       ahead market to participate in, and, but, you  
4       know, we just assume that they're going to be  
5       online and so we don't need to give them an RMR  
6       contract, I mean, I think that that's problematic.

7               CHAIRPERSON GEESMAN:   Yes.

8               MR. MICSA:   One other issue I wanted to  
9       raise here is that the RMR contracts do not have  
10      to be signed by October.   The RMR contracts can be  
11      signed all the way until the need arises, which  
12      could be next June or July.   We have to send --

13              CHAIRPERSON GEESMAN:   Which you've  
14      recently demonstrated.

15              MR. MICSA:   Yes.   We have to send the  
16      cancellation notices by October 1st.   We can sign  
17      the units all the way until the need arise.

18              MS. KAPLAN:   Thank you.   That was my  
19      misunderstanding.

20              MR. TRASK:   Katie, I had a question  
21      about one of the comments you made.   You said  
22      something about two-thirds of the plants in the  
23      L.A. area supply local reliability.   Can you  
24      expand a little bit on that?

25              MS. KAPLAN:   Sure.   And I think it

1       probably, I mean, Catalin's probably going to have  
2       a different perspective than I do.

3               But, you know, essentially what's  
4       happening is that when our units are being called,  
5       they're being called through the dispatch order  
6       from the operators, for local reliability. Now,  
7       the ISO, and I think they'd probably agree with  
8       me, is having a difficult time defining what  
9       local reliability is, and what the local  
10      reliability needs of the grid are.

11             And so all we know, though, is that when  
12      we're being called it's not for a system need,  
13      it's not for a zonal need, it's for a local  
14      reliability reason. And those were the three  
15      different criteria that the ISO articulated as  
16      part of the must-offer process in order to correct  
17      the cost allocation issue associated with must-  
18      offer.

19             And so, you know, I don't know what the  
20      definition of a local reliability need is. The  
21      must-offer obligation, the criteria that the  
22      operators are using every day on a day-to-day  
23      basis to keep the grid on, is, I think, a little  
24      bit different than the local reliability criteria  
25      that's being utilized for RMR. And we're trying

1 to bring those together. But, you know, unless  
2 those criteria are the same, it's, it's the must-  
3 offer criteria, it's the RMR criteria, it's  
4 criteria for mitigation of local market power, all  
5 different. And they have to come together.

6 And so, you know, when a unit is needed,  
7 they can be, they can know that they're being  
8 needed for a local reliability reason, they get an  
9 RMR contract. They're not needed, they don't get  
10 mitigated through local market power under normal  
11 circumstances. You know, I mean, obviously if  
12 something happens in the grid, there's always that  
13 need. But, you know, under a normal circumstance,  
14 all of those criteria should line up from the  
15 beginning to the end, from the planning process to  
16 the real time operations process.

17 CHAIRPERSON GEESMAN: And just to be  
18 clear, in terms of the population of plants in our  
19 study, you're talking about a problem that exists  
20 in southern California, in the ISO control area  
21 for plants that do not currently have RMR  
22 contracts or are otherwise contracted for, such as  
23 the AES projects that we heard about earlier.

24 MS. KAPLAN: That's correct. And then  
25 we are also looking for, looking toward the plants

1       that will be -- have bilateral contracts with the  
2       state that expire at the end of the year.

3               CHAIRPERSON GEESMAN:   Okay.

4               MR. LEE:   Commissioner Geesman.

5               CHAIRPERSON GEESMAN:   Yes.

6               MR. LEE:   I guess I'm here just to  
7       justify and concur with, with what Katie said.  
8       We've had a lot of experience in ISO using, not  
9       necessarily letting us know that those are, what  
10      was the purpose for the use of the units, but you  
11      can kind of guess that that was an RMR use.  Among  
12      all the 12 units that we have in southern  
13      California, only two of them have RMR designation,  
14      but most all of them are being used under the  
15      rolling must-offer.

16              CHAIRPERSON GEESMAN:   Yes.  Yes.

17              MR. TRASK:   Any other comments on this  
18      topic?

19              MR. LAYTON:   This is Matt Layton.  
20      Katie, you made reference to dirtiest plants being  
21      dispatched.  What environmental attribute and  
22      which plants might those be?

23              MS. KAPLAN:   Well, I mean, I probably  
24      didn't -- I used that as sort of a general term.  
25      I would say, you know, if they're older plants

1       they're probably less efficient than the new  
2       plants.

3               MR. LAYTON:   So the gas use is the  
4       issue?

5               MS. KAPLAN:   Probably.  I probably, I  
6       would withdraw that.

7               MR. LAYTON:   Okay.  I just was curious.  
8       I'd like to know if I'm missing something.  Thank  
9       you.

10              MS. KAPLAN:   I don't think --

11              CHAIRPERSON GEESMAN:  I'm sure she  
12       wouldn't refer to any of her members as dirty.

13              (Laughter.)

14              MS. KAPLAN:   No.  Some of my non-  
15       members, maybe.

16              MR. TRASK:   Okay.  I have heard that  
17       Trent Carlson has landed and should be here in  
18       about ten minutes.

19              CHAIRPERSON GEESMAN:  Oh, good.

20              MR. TRASK:   Oh, he is here.  Okay.

21              CHAIRPERSON GEESMAN:  Great.

22              MR. TRASK:   Well, do we want to go ahead  
23       and then do that presentation now?

24              CHAIRPERSON GEESMAN:  Yeah, I think  
25       that'd be a good idea.

1           MR. TRASK: Okay. For some reason my  
2 computer here has frozen up, so perhaps Trent can  
3 get going without the presentation.

4           MR. CARLSON: Well, good afternoon.  
5 First, let me start off by apologizing for being  
6 late. I intended to be here earlier this  
7 afternoon. I ran into a few difficulties, but I'm  
8 glad to be here, more than you know.

9           Actually, I am really glad to be back.  
10 I lived in California for over 15 years. I've  
11 been away for three, working in the Ercot ISO  
12 predominantly. But I've been back, had occasion  
13 to come back. I guess this would be my seventh,  
14 seven month anniversary of being back and working  
15 on resource adequacy, must-offer waiver denial,  
16 short-term reliability contracts, RMR, core, non-  
17 core, all that I think is important, all that our  
18 company believes is important and is very much  
19 related to the subject matter of aging power  
20 plants. So thank you very much for having the  
21 opportunity to address the Commission and the  
22 audience.

23           I'm going to try and do this without my  
24 presentation, so I apologize for that. But --

25           CHAIRPERSON GEESMAN: Your presentation

1 may catch up with you in about --

2 MR. TRASK: Yeah, we're, we're trying  
3 here.

4 MR. CARLSON: All right.

5 CHAIRPERSON GEESMAN: There we are.

6 MR. CARLSON: That's not it.

7 Again, my name is Trent Carlson. I'm  
8 with Reliant Energy. I work in the regulatory  
9 affairs department. Before coming to Reliant  
10 Energy, I had mentioned that I had lived here for  
11 15 years, about the last five of that I worked as  
12 the Director of Operations Support and Training at  
13 the California Independent System Operator. And  
14 there I became familiar with both the operation  
15 side as well as the market side of how California  
16 was at least working then. And so that, to some  
17 extent, I guess in great degree, influences my own  
18 personal opinions, as well as the way in which I  
19 contribute at Reliant.

20 I'm not sure if, if the Commissioners  
21 know this, but Reliant is a very different company  
22 these days. We're hundreds of employees shorter,  
23 we're operating much leaner, we've renewed our  
24 commitment to the state of California as of about  
25 seven months ago, and we are really focused on

1 contributing not only as a generator, but also to  
2 see the retail market develop here, as well. We  
3 want to be a part of maintaining reliability and  
4 being a good citizen within the state of  
5 California, and in particular in electric markets.

6 Now, specifically to the point of the  
7 aging power plant study. I'd like to start off by  
8 suggesting or recommending that the aging power  
9 plant study clearly indicate that these aging  
10 steam and gas turbine power plants are a  
11 foundation of California's electric supply system.  
12 Without them, I think it's pretty clear, and it's  
13 probably been discussed already this morning and  
14 this afternoon, that without this capacity we'd be  
15 in a very difficult situation come this summer.

16 In fact, in the absence of at least a  
17 few generating units, there's been some  
18 difficulties of late, principally because many of  
19 these aging power plants cannot make it in the  
20 spot energy market alone. They just can't.  
21 They've got fairly low cost capacity, but they  
22 don't have heat rates that can compete with the  
23 newer technology energy production plants.

24 We also believe that this aging power  
25 plant study has really turned the, not only the

1 tone, but the -- it's turned a couple of  
2 assumptions into a different set of facts. For  
3 example, as I read the available materials several  
4 months ago, I think one of the going in  
5 assumptions was that these aging power plants were  
6 dirty, that they contributed excessively to  
7 emissions. I think the, if my understanding of  
8 the aging power plant study is correct, it's shown  
9 that, or the Energy Commission study has shown  
10 that the vast majority of these plants have either  
11 selective catalytic reduction or best available  
12 control technology. And with their low, actually  
13 in some cases very, very low capacity factors,  
14 they're not a significant contributor to  
15 emissions.

16 So I thought that was, that's been very  
17 helpful in this study, and we're hopeful that the  
18 Energy Commission's aging power plant study will  
19 reflect that.

20 As I mentioned earlier, the aging power  
21 plants, many of them cannot survive on energy spot  
22 market alone. And Reliant has participated in  
23 several forums, including the Silicon Valley  
24 manufacturing groups' development of a straw  
25 proposal for resource adequacy, in which capacity,

1 including capacity associated with aging power  
2 plants can be tagged, it can be counted so as to  
3 avoid double counting, and it can, it can serve as  
4 the basis for a tradeable market for capacity.  
5 And ultimately, our hope, and I think the hope of  
6 several of the load-serving entities including  
7 energy service providers that I've talked to,  
8 their hope is that we're going to create a  
9 capacity product that does not create new stranded  
10 costs. But, in fact, we're going to create a  
11 process that avoids or eliminates the prospect of  
12 newly created stranded costs.

13 So we kill two birds with one stone, if  
14 you will, if we continue to move in the direction  
15 of first recognizing that resource adequacy is job  
16 one, the aging power plants are key, they're  
17 foundational, in achieving resource adequacy, and  
18 that resource adequacy must be achieved now. It  
19 really can't be achieved in 2008. And I know,  
20 Commissioner Geesman, you've joined with President  
21 Peavey of the CPUC and Governor Schwarzenegger in  
22 encouraging a moving up of that timeline from 2008  
23 to something much, much closer. As well, the WPTF  
24 has come alongside the three of you and filed a  
25 petition for modification of the CPUC's January

1 order in which they suggest that the deadline be  
2 moved up to May 2006.

3 CHAIRPERSON GEESMAN: Yeah. I would  
4 suggest to you that the three of us aren't as  
5 significant as three PUC commissioners would be.

6 MR. CARLSON: Well, in, in my 15 years  
7 in California I never distinguished that  
8 difference, but I never worked at an investor-  
9 owned utility company, either, so that difference  
10 has been lost on me to this point, or to this  
11 point.

12 In closing, there are several very  
13 important regulatory proceedings, some of which  
14 are further along than others, some of which have  
15 issues that are much, much older than others, and  
16 some of which have introduced some new ideas that  
17 go right to the heart of solving the resource  
18 adequacy problem.

19 One of those older proceedings is the  
20 market design 2002 at the California ISO. In  
21 March 3 through 5, it became, I believe, in my  
22 opinion, crystal clear that MD02, as it's referred  
23 to, will simply be problematic in the absence of  
24 resource adequacy. There were experts from the  
25 east and there were experts from the west. There

1       were experts from several regulatory agencies,  
2       both state and federal, that seemed to agree on  
3       that fact that we need resource adequacy and  
4       market design 2002. Resource adequacy, in our  
5       opinion, and I believe that several, I know that  
6       several share this opinion, resource adequacy is  
7       going to be the foundation of any market design or  
8       any market design changes. And our experience  
9       tells us that we won't be done with MD02 whenever  
10      it gets here.

11               Between now and then, we have a real  
12      serious problem with must-offer waiver denial.  
13      And just to step back from the immediate problem  
14      of it not always being compensatory, we'll set  
15      that aside for a moment. And I would propose to  
16      the Commission, and suggest that it be included in  
17      the aging power plant study that the must-offer  
18      waiver denial process has gotten in the way of  
19      proper incentives; in fact, serves as a  
20      disincentive to supply. It gets in the way of  
21      resource adequacy. It sends the wrong signals.

22               Now, on my way here I was told that  
23      you've already discussed Etiwanda in some degree.  
24      I think it's a, it's a great case in point that  
25      could be described in the aging power plant study

1 as the disincentives that surround the energy  
2 market at this time, and have resulted in a  
3 critical resource not being available, and, in  
4 fact, being moved into mothball state by our  
5 company because that resource is not competitive  
6 in the spot energy markets, based on the  
7 conditions that are designed into it.

8 Along those lines, we'd also like to see  
9 the aging power plant study make reference to the  
10 California Independent Energy Producers  
11 Association's comments filed in response to the  
12 California ISO's amendment, proposed amendment 60  
13 to its tariff. In that IEPA filing, you'll see a  
14 proposal referred to a short-term reliability  
15 contracts. It picks up on an idea that the ISO  
16 itself included in its own filing. The ISO  
17 identified the must-offer waiver denial process as  
18 being problematic, listed all of the problems, and  
19 said that the solution was to contract for these  
20 resources. But in the same paragraph also  
21 mentioned that they were worried that it become as  
22 contentious as the original formulation of the  
23 reliability must-run contracts.

24 I believe our company believes that the  
25 proposal inside the IEPA's amendment 60 comments

1 is that answer, that the CALISO said should be the  
2 solution. Short-term reliability contracts are  
3 referred to as STRC.

4 And then finally --

5 CHAIRPERSON GEESMAN: Let's hold on that  
6 one for a minute, Trent.

7 MR. CARLSON: Okay.

8 CHAIRPERSON GEESMAN: Because I, I'm  
9 having a problem just looking at the months ahead.  
10 Our report will have some salience from, say,  
11 November 1 onward. It's not going to be embraced  
12 or officially blessed by the full Commission  
13 until, until November 1st, so look at that as a  
14 train that doesn't leave the station for another  
15 four, five, six months. Five months, I guess.

16 You've got RMR contracts that are at  
17 least ostensibly being reformulated in September.  
18 My question for you is the same one I had for  
19 Katie. Knowing something about the ISO, and the  
20 process by which their decision makers can come to  
21 conclusions, why should we have any faith that a  
22 completely new instrument will be able to be  
23 adopted in a timely fashion, rather than  
24 attempting to expand or reconfigure the existing  
25 instrument of, of the RMR contract?

1 MR. CARLSON: I'll give you my top  
2 several reasons. Thank you for asking the  
3 question.

4 What the IEPA has proposed in its  
5 amendment 60 comments is a procedure, or a  
6 contracting method that can be implemented now  
7 without alteration amendment of the California  
8 ISO's tariff. That's point number one.

9 CHAIRPERSON GEESMAN: Okay. And you're  
10 sure of that?

11 MR. CARLSON: Yes, sir, I am.

12 CHAIRPERSON GEESMAN: Nobody's going to  
13 -- nobody's going to file a complaint at FERC  
14 contesting that.

15 MR. CARLSON: Oh, somebody, if -- that,  
16 I cannot warranty or guarantee.

17 CHAIRPERSON GEESMAN: None of the usual  
18 suspects will file a complaint at FERC contesting  
19 that.

20 MR. CARLSON: If you include the  
21 California ISO as one of these usual experts, or  
22 one of the usual suspects, in my opinion, you're  
23 not going to see them file against it. You're  
24 going to see them file in support of it. And I  
25 can give you the reasons why, if you'd like.

1           The reasons I have, one in particular,  
2       is I've had a recent telephone conversation with  
3       one of the management team at the California ISO,  
4       and when we were talking about doing a short-term  
5       RMR contract for Etiwanda, we were exploring the  
6       possibilities of how to actually get something  
7       like that accomplished. And I mentioned, actually  
8       another person at my company mentioned that we  
9       could probably do it without a contract. And the  
10      -- I mean, without an RMR contract, but with one  
11      of the short-term contracts. At that time the  
12      STRC concept had not been fully developed yet and  
13      filed by IEP.

14           And the person at the California ISO  
15      responded by, okay, Trent, now we don't want to  
16      hear that speech again about how we can do this  
17      under the existing California ISO tariff. We  
18      understand that, we don't want to hear that speech  
19      again. I'm not sure if, if that representative of  
20      the California ISO will be here later today. It  
21      was neither of them, so they're safe.

22           But I'm very confident in that, and I --

23           CHAIRPERSON GEESMAN: But I understand  
24      that in that particular situation, the ISO chose  
25      to, to rely again on the RMR instrument as, as the

1 preferred way of achieving some contractual  
2 certainty.

3 MR. CARLSON: It saw it as the most  
4 expeditious way to maybe manage what you had  
5 suggested earlier, Commissioner Geesman, and that  
6 is to manage the usual suspects in a, a filing of  
7 this document at the FERC.

8 CHAIRPERSON GEESMAN: All right.

9 MR. CARLSON: But I would still come  
10 back to my proposition, and that is the ISO has  
11 gone down on paper and filed it at FERC that the  
12 solution to the must-offer waiver denial process  
13 is short-term reliability contracting. I'm trying  
14 to remember off the top of my head what page it  
15 is. CALISO sitting behind me might even have that  
16 memorized. But they've identified it as a  
17 solution. We believe it is a solution. We  
18 believe that IEP has done a great job of  
19 describing how to actually get that done.

20 CHAIRPERSON GEESMAN: You know, I still  
21 am looking for something more perhaps expedient  
22 than that. I think that the considerations that  
23 led the ISO to opt for the RMR instrument in the  
24 Etiwanda setting prevail today every much as,  
25 every bit as much as they did last week, and are

1       likely to prevail in the, the weeks and months  
2       ahead. I think your, your situation calls out for  
3       a timely response, and I'm not certain that a new  
4       instrument is available in a timely way.

5               I know you're going to, you're going to  
6       tell me that with the exercise of willpower  
7       anything is possible, but I'm looking at the ISO  
8       as a little, a little less certain or a little  
9       less stable, perhaps, than they were a week ago,  
10      in terms of their internal decision making  
11      process. And I think that we ought to be looking  
12      for, for mechanisms that simplify going forward,  
13      rather than, than adding to complexity, even if  
14      the simplification is less than idea.

15             MR. CARLSON: I, I hear you, and I agree  
16      with you, and I, I would share an observation and  
17      a suggestion, or renew the suggestion.

18             The observation is that when I was here  
19      for 15 years, I'd never seen the Governor's office  
20      -- there were several governors -- the, the  
21      Governor's office, the CPUC and the CEC so much so  
22      on the same sheet of music, and now, including the  
23      California ISO. And I'm seeing the California ISO  
24      take action now that I would not have expected,  
25      even a few weeks ago, and I'm not sure that it, it

1 has much to do with recent events at the  
2 California ISO more than it does with events that  
3 have occurred of late in the transmission grid  
4 that have been made public, not the least of which  
5 is the May 3, 2004, transmission emergency.

6 That was the underlying and exclamation  
7 mark to a series of events that have occurred over  
8 the course of -- well, ever since the must-offer  
9 waiver denial was implemented, where there was a,  
10 a clear problem that was clearly understood, that,  
11 for whatever reasons, was not getting solved. And  
12 I think the Energy Commission's work, not only in  
13 this aging power plant study, has brought to it,  
14 to the attention of, I'll just say everyone.

15 The problem we're dealing with here, the  
16 previous studies that the Energy Commission has  
17 done and their view of 2004 and 2005, my idea in  
18 response to your suggestion that we need something  
19 more off the shelf, I would suggest that, that  
20 even though the study's not going to be out until  
21 November, between now and November the Energy  
22 Commission can make its findings and its opinions  
23 known. People listen. I don't think Reliant  
24 Energy is the only person, or the only company  
25 that listens to the Energy Commission. And I

1 think the California ISO is not only listening to  
2 the Energy Commission and the findings that you  
3 all have come to to this point, I think they're  
4 acting in similar stead. I think --

5 CHAIRPERSON GEESMAN: I think that's  
6 right.

7 MR. CARLSON: And I think there's, there  
8 is a huge opportunity now that, for a whole host  
9 of reasons, didn't even exist a few months ago.  
10 And I, I believe that we can seize this moment. I  
11 believe that we can bring together a group of  
12 people that includes generators, LSEs, CPUC,  
13 Energy Commission, Governor's Office, and sit  
14 down, and as a starting point there is maybe  
15 other, there may be other starting points, but as  
16 a starting point, the IEP's short-term reliability  
17 contract mechanism, and just put a cover letter on  
18 it, put it into a standard form with the  
19 boilerplate, and convert all of those recurring  
20 must-offer waiver denial generating plants to  
21 short-term reliability contracts, and get that  
22 done, get it done now, and have that in place  
23 until we have resource adequacy and MD02 fully  
24 implemented.

25 CHAIRPERSON GEESMAN: Tell me why you're

1       confident about the response of the LSEs.

2               MR. CARLSON: I'll speak frankly, with  
3       your permission.

4               CHAIRPERSON GEESMAN: Please.

5               MR. CARLSON: I told you I just got  
6       involved seven months ago, and I've mentioned that  
7       I've seen the Energy Commission, the CPUC and the  
8       Governor's Office all on the same sheet of music.  
9       And the California ISO. There's also been events  
10      in the power system that have been reported in the  
11      public press. And it's, it's clear that there's  
12      not only a lack of incentive to contract, there  
13      are disincentives to contract. At the same time,  
14      there is the California ISO that is charged with  
15      the responsibility of grid reliability. And we  
16      are at a point to fish or cut bait, and lacking  
17      another alternative to short-term reliability  
18      contracts I don't see anybody pushing back to  
19      solving what is obviously a summer 2004  
20      reliability problem, a potentially even worse  
21      summer 2005 reliability problem, if the  
22      disincentives persist, if there's, there's no  
23      contracting, and if the owners of many of these  
24      aging power plants are forced to make an economic  
25      decision to mothball or retire plants. Many of

1       those companies have either shareholders or  
2       stakeholders that they're responsible to, and they  
3       have to make decisions on their behalf. That's  
4       their constituency.

5               I think everybody's arrived at the same  
6       point, Commissioner Geesman, and that's why I just  
7       feel, as you can tell, pretty strong about it. I  
8       think we're --

9               CHAIRPERSON GEESMAN: Yeah, but it, it  
10      looks to me like the LSEs have taken a fair amount  
11      of comfort in the spot market, in terms of  
12      addressing what, what they perceive to be the  
13      reliability needs of, of the system.

14              MR. CARLSON: I can't speak to what  
15      degree of comfort the LSEs have taken. I can only  
16      observe, as I understand you're observing that  
17      they're not contracting for these resources. But  
18      the May 3 event is the last one I can think of,  
19      where there was a transmission emergency. That  
20      resource needs to be contracted.

21              CHAIRPERSON GEESMAN: Well, I would  
22      submit --

23              MR. CARLSON: Do we need to -- do we  
24      need to jump through --

25              CHAIRPERSON GEESMAN: -- that the staff

1 forecast that we released at the end of the week  
2 last week suggests similarly, although it  
3 certainly has not been construed that way. But my  
4 impression was that the ISO encouraged Edison to  
5 sign a contract. I'm not certain they called it a  
6 short-term reliability contract, but I don't think  
7 they called it an RMR contract for Reliant, and  
8 that Edison said well, make it an RMR project.  
9 And, you know, with, with that RMR designation it  
10 looks to me as if things have moved forward.

11 That's why I, I'm -- because of the, the  
12 pressure of time, I think we're forced towards  
13 some, some paths of least resistance in terms of  
14 securing adequate resources. I can't claim to, to  
15 have full insight into all of the cost recovery  
16 strategies or psychologies that may prevail at the  
17 different LSEs, but it does appear to me that,  
18 that you've got to make particular pronouncements  
19 or provide a particular handshake for, for them to  
20 gain comfort they will be able to recover those  
21 costs.

22 And I think that, that the situation  
23 that the state confronts, both with respect to '04  
24 and potentially with respect to '05 and beyond,  
25 would suggest we need to address these questions

1       sooner, rather than later. The Energy Commission  
2       I think can do its part to try and draw attention  
3       to that need, but, you know, there are an awful  
4       lot of cooks in this kitchen, not just here in  
5       this building, but throughout this town and in San  
6       Francisco, and out in Folsom, and back in  
7       Washington, D.C. The chairman of FERC describes  
8       this as a rosary bead summer. You don't hear  
9       quite those terms here on the west coast, but I'm  
10      not certain that the reality is any different in  
11      terms of, of taking a careful look at the  
12      situation.

13               MR. CARLSON: I agree with you  
14      completely. Actually, there may be a way to do  
15      this sooner rather than later. And I'll think a  
16      little bit outside of the box -- just slightly,  
17      though, because again, I truly believe that the  
18      Governor's Office, the CEC, the CPUC and the  
19      CALISO are on the same sheet of music.

20               Along those lines, the CALISO  
21      understands that the solution is a short-term  
22      reliability contract. They understand that must-  
23      offer waiver denial is a disincentive to resource  
24      adequacy. It's a disincentive to contracting.  
25      It's not a disincentive to mothball or retire.

1 They also know that they need this capacity now,  
2 and they're going to need it at least in 2005-  
3 2006.

4 CHAIRPERSON GEESMAN: Well, now, tell me  
5 why your experience with the Etiwanda plant isn't  
6 a perfect endorsement of the existing approach to  
7 mothballing.

8 MR. CARLSON: I'm getting to the  
9 solution. Here we are, we're -- we are standing  
10 on the brink of a solution, and I, and I'm  
11 confident that the CALISO will give this serious  
12 consideration because this is a very serious  
13 matter. And as a, as a very serious suggestion to  
14 implement your idea of doing something sooner  
15 rather than later, the CALISO would serve to  
16 benefit everyone if they would take action with  
17 respect to their amendment 60, respond to IEPA's  
18 comments in amendment 60, and at least endorse the  
19 concept of immediately implementing a short-term  
20 standard form reliability contract that is not  
21 caught up in the annual LARS RMR process, that the  
22 CALISO could lead that effort based on their own  
23 suggestion in their own amendment 60 filing that  
24 their solution is to contract.

25 I believe that the part --

1                   CHAIRPERSON GEESMAN: And you feel --

2                   MR. CARLSON: -- excuse me.

3                   CHAIRPERSON GEESMAN: And you feel they  
4 could do that under their existing tariff  
5 authority, and you feel that none of the top three  
6 LSEs would protest that. I'm putting words in  
7 your mouth on the latter point.

8                   MR. CARLSON: On the latter point, we'll  
9 just have -- they'll have to, they'll have to  
10 speak for themselves. I could see them, I could  
11 see them potentially pushing back -- I could even  
12 see the California ISO potentially pushing back.  
13 It's not that IEPA has thought every thought, has  
14 dotted every "i", crossed every "t" in a proposal.  
15 But we believe it's a well thought out proposal.  
16 We've discussed it with several parties. We've  
17 discussed, at least informally, the concept with  
18 the California ISO recently, and when I worked at  
19 the California ISO we came up with a very similar  
20 concept that was called short-term reliability  
21 service, or the STARS agreement. But it was  
22 overtaken by RMR, and then later LARS RMR events,  
23 and you might say the attorney profession  
24 overwhelmed the engineering and operations  
25 profession.

1                   CHAIRPERSON GEESMAN: As it often does.

2                   MR. CARLSON: Not, not necessarily to a  
3 completely bad outcome. At least there's a  
4 reliability must-run contract. But it really does  
5 not fit all of the real time grid operations. It  
6 doesn't, you can't guess what your transmission  
7 outages are going to look like tomorrow or next  
8 week, when you're doing it six months or a year  
9 ago.

10                  So I would, I'm hoping that I'm not  
11 arguing with you.

12                  CHAIRPERSON GEESMAN: I don't think you  
13 are.

14                  MR. CARLSON: I hope I'm agreeing with  
15 you, and I'm hoping that, I'm hoping that the  
16 representatives of the California ISO that are  
17 here today, and the representatives of California  
18 IEPA will join together and get done what I'm  
19 hearing you say get done. And that is something  
20 now, something sooner, rather than later.  
21 Something that comes before the November release  
22 of the aging power plant study.

23                  And I can tell you this, and there's  
24 officers of the company here, and they can step up  
25 here and clarify if they, if they want. But

1 Reliant is fully on board and will devote whatever  
2 time is required and whatever capability we have  
3 to helping get this done just as you've proposed,  
4 Commissioner Geesman, now, as opposed to later.

5 CHAIRPERSON GEESMAN: Well, I, my advice  
6 to you would be to round up some LSEs,  
7 particularly those in southern California, and  
8 particularly those headquartered in Rosemead.

9 (Laughter.)

10 MR. CARLSON: Okay. I'll, I'll follow  
11 up and see if I can find a large utility in that  
12 area.

13 (Laughter.)

14 MR. CARLSON: I, I follow you, sir, and  
15 we will follow up accordingly with the California  
16 -- starting with the California ISO and the  
17 California IEPA. And anyone else that's here in  
18 the audience or possibly even, respectfully so,  
19 sitting on your side of the table, we greatly  
20 appreciate the work that the Energy Commission has  
21 done to this point. And we're, we're here to  
22 help. It's the new face of this company, and we  
23 want to show you that we're serious.

24 CHAIRPERSON GEESMAN: I appreciate your  
25 remarks, Trent.

1 MR. TRASK: Do we have any other  
2 questions for Trent?

3 Thanks for your presentation, and I'm  
4 glad you made it out here today.

5 MR. CARLSON: All right. Thank you.

6 CHAIRPERSON GEESMAN: What's next, Matt?

7 MR. TRASK: I'm -- I've gotten through  
8 only the first question under the role that the  
9 plants play.

10 In the interest of time, I'm going to  
11 propose that we skip the rest of the questions,  
12 which actually I think we've covered fairly well  
13 at previous, previous workshops. They primarily  
14 deal with the selection of the plants that we have  
15 on our study list. I think we've batted that  
16 issue quite well.

17 And perhaps the only other area that I  
18 might want to talk about right now is not  
19 specifically applicable to this study, but perhaps  
20 future studies. I'll just read the question.

21 Other concerns expressed -- are the  
22 concerns expressed about the aging steam boiler  
23 plants applicable to other general categories of  
24 generators, such as peaking plants, nuclear plants  
25 or hydroelectric plants.

1           Actually, Catalin, did you want to  
2       respond to some of the previous comments? Any  
3       comment on that question?

4           I'm going to propose that we move into  
5       the next panel, which is present and anticipated  
6       plans, policies and projects that could affect  
7       aging plant economics. And it goes to the, the  
8       meat of the issue here.

9           What are the likely effects on aging  
10      plant economics, and decisions to retire, of the  
11      pending decisions of the CPUC concerning resource  
12      adequacy, procurement and locational pricing.

13          Any comments from the audience on that  
14      issue?

15          MS. THOMAS: Are you looking for an  
16      update on the proceeding?

17          MR. TRASK: Sure.

18          MS. THOMAS: Okay. I don't know if  
19      David was there. David's been participating in  
20      most of these proceedings.

21          But the ISO has -- had expressed concern  
22      that resource adequacy is the first obligation  
23      prior to price or procurement. And in the  
24      proceedings it seems that there has been some  
25      consensus that has, that, that there's an

1       agreement that resource adequacy, or the  
2       obligation to, to create a resource adequacy and  
3       that reliability is served first has been a  
4       consensus. And, and that -- and again, that  
5       reliability is considered first, prior to  
6       procurement.

7               CHAIRPERSON GEESMAN: Yeah. I'm  
8       concerned that the way in which we at the Energy  
9       Commission and at the Public Utilities Commission,  
10      and also at the Legislature, tend to express  
11      resource adequacy, is in terms of statewide  
12      aggregates. And I don't think our reliability  
13      problems crop up as statewide problems. I think  
14      they're highly localized, and difficulties that we  
15      face on the intra-state transmission system  
16      prevent statewide numbers from necessarily being  
17      very reflective of the, the prospect of being able  
18      to address localized reliability problems.

19             And I wonder, I wonder if you've got a  
20      reaction to that. I mean, we, we talk in terms of  
21      a statewide reserve requirement. It's, it's a  
22      little hard for me to, to derive complete  
23      satisfaction from that when I know that under  
24      certain circumstances, those statewide reserves  
25      will be of no assistance to a problem in a local

1 reliability area.

2 MS. THOMAS: The ISO also believes that  
3 that is extremely important, and that local areas,  
4 as well as the statewide, need to be considered.  
5 And being able to evaluate not only what capacity  
6 is available, for instance, in the FP15, how much  
7 capacity is available in the north, and can we  
8 move it down to the south. And those, we've  
9 expressed at the PUC proceedings that, that local,  
10 localized, localized pockets need to be  
11 considered, and that deliverability needs to be  
12 proved. And so that, it seems that there's some  
13 consensus that, that local pockets and  
14 deliverability will be addressed in those  
15 proceedings.

16 CHAIRPERSON GEESMAN: I really  
17 encourage you to continue to reiterate that,  
18 because I, I think the tendency on the part of  
19 entities that have statewide responsibilities is  
20 to rest behind those aggregated numbers, and I  
21 think that that can really mask some underlying  
22 problems.

23 MS. THOMAS: I think Phil Pettingill,  
24 who was here earlier, attends all these PUC  
25 proceedings, and I think he mentions that at least

1 four or five times during each workshop, so.

2 CHAIRPERSON GEESMAN: Good.

3 MS. THOMAS: It's a very important issue  
4 to the ISO.

5 MR. MICSA: That was one thing that was  
6 missing from, from the PUC. Actually, the  
7 language had come up, it only had the least cost.  
8 And, you know, you can, you can buy 20,000  
9 megawatts in Arizona, but you cannot cross it  
10 over. And that, that's not least cost. So  
11 reliability has to be put before least cost.

12 CHAIRPERSON GEESMAN: Well, and I think  
13 that our record as it relates to permitting  
14 particular transmission projects would suggest  
15 that we're not to be trusted in terms of taking  
16 into consideration some of those localized  
17 concerns. So the more that point is reiterated,  
18 hopefully the sooner it will get across.

19 MR. TRASK: Any other comments from the  
20 audience?

21 The next question. What other pending  
22 or active regulatory proceedings or legislative  
23 bills would affect aging plant economics and  
24 decisions to retire?

25 Are there any transmission projects or

1 upgrades that will likely affect the RMR status of  
2 any unit on the APPS study list during the  
3 timeframe of 2004 to 2008?

4 MR. MICSА: Well, there could be some  
5 projects. The only ones that we have approved  
6 right now it's the Mira Loma Bank and Mira Loma  
7 Etiwanda reconductoring. So if that comes on next  
8 year there is a possibility that Etiwanda may get  
9 more involved again, unless we change the RMR  
10 criteria or we have some kind of a short-term  
11 reliability contract, whatever that is.

12 CHAIRPERSON GEESMAN: Does the Mira Loma  
13 project require CPCN?

14 MR. MICSА: No, it's a reconductoring.  
15 It's an existing right-of-way, existing line,  
16 changes the conductor to a higher rating.

17 MR. TRASK: My understanding was that  
18 some of the resources that were going to go to  
19 those upgrades in those areas had to be diverted  
20 to repair some of the damage done by the, the  
21 fires last year. That was one of the reasons for  
22 the delay.

23 Trent wanted to speak a little bit to  
24 the, to the last question about --

25 CHAIRPERSON GEESMAN: I think I see Gary

1 Schoonyan finally coming up to the microphone.

2 MR. SCHOONYAN: Gary Schoonyan, Southern  
3 California Edison Company.

4 I, I do want to comment briefly on the,  
5 that third question. One of the things that we  
6 have proposed to the ISO since I believe 2002, and  
7 every year it's been denied, is the Stagecoach 500  
8 kV substation which, is if were approved in 2002,  
9 would most likely be in place today and there  
10 wouldn't be an RMR problem or concerns in the  
11 Etiwanda area.

12 So I, I guess what I, my charter to the  
13 ISO is approve Stagecoach so at least it'll be in  
14 place in 2008 and we won't have to deal with a lot  
15 of these remedial and other sorts of approaches.

16 CHAIRPERSON GEESMAN: What have you seen  
17 as the problem for, for that project getting  
18 approved?

19 MR. MICSA: We have, we have sent  
20 comments back to Edison requesting additional  
21 information why we haven't approved it. But we  
22 have also approved for Mira Loma Bank and the line  
23 that we'll take care of the local area problems,  
24 and we're not done. So I would tell Edison please  
25 put your projects online if you propose them.

1           MR. SCHOONYAN: Our project is online.  
2       The three reconductoring, not reconductoring, but  
3       the, the clearance problems and the wave trap  
4       problems, they're, they're available now. The,  
5       the system can, is capable, should be capable of  
6       going to 5100. There is another thing that I  
7       believe you, the ISO has proposed with regards to  
8       looping the Lugo Serrano line into Mira Loma,  
9       which would add another 300 megawatts of transfer.  
10      That's my understanding.

11           The concern there is, is that there are  
12      de-looping problems associated with that under  
13      certain operating conditions. It becomes sort of  
14      an operating concern from our perspective as  
15      transmission owners. The right thing, the correct  
16      thing has always been to build Stagecoach. It's  
17      been proposed three times to the ISO and denied  
18      three times.

19           CHAIRPERSON GEESMAN: So there's a, a  
20      difference of opinion between, between your  
21      engineers and the ISO's engineers?

22           MR. SCHOONYAN: I, I'm not sure about a  
23      difference of opinion. With regards to the value  
24      of Stagecoach, I do not believe there is a  
25      difference of opinion. I'm not sure what the

1 concerns are that the ISO has expressed in denying  
2 it, other than my guess, and I'm speculating on  
3 this because I, I don't know, would be just the,  
4 the price tag associated with it versus some of  
5 these other schemes. The arrangement that we  
6 proposed to basically increase the -- or decrease  
7 the amount of sag and put wave traps in and what  
8 have you, was a five, six, \$7 million item. The,  
9 the additional Double A bank, which was correct, I  
10 think Matt mentioned it, when we had the Double A  
11 bank fire up in Vincent, we had to relocate that.  
12 That's been taken, that's about 18, 14, \$15  
13 million. The new substation's about 80 million  
14 bucks. And when it's fully built out will be over  
15 100 million.

16 So the only thing that we, from our  
17 perspective, is, is a cost issue as it relates to  
18 the, the way the ISO is looking at it.

19 MR. MICSA: And we have sent comments  
20 back to Edison. They haven't gotten back with  
21 sufficient response to us to be able to approve  
22 the bank. It was not denied, it was turned back  
23 for additional support. We didn't have enough  
24 additional support. The substation won't do  
25 anything to alleviate the skid problems or even

1 solve Lugo.

2 MR. SCHOONYAN; I disagree. The  
3 substation will increase the south of Lugo  
4 transfer from 50 -- currently, it was 4400, the  
5 fixes that we've put in place brought it up to  
6 5100, Stagecoach will bring the 5100 up to 5900.

7 MR. MICSA: Okay. We'll do something  
8 for the --

9 CHAIRPERSON GEESMAN: Thanks, Gary.

10 MR. TRASK: Trent, you want to jump in?

11 MR. CARLSON: Yes, thank you, Matt.

12 I wanted to back up to the question  
13 about regulatory proceedings that tie into this.  
14 I had mentioned them briefly at the first part of  
15 my statement when I last spoke. There's basically  
16 three of them, but I'll, I'll list them for you as  
17 four pieces.

18 The first being the CPUC's resource  
19 adequacy workshop report that is expected out real  
20 soon, that's, that will overlap the beginning of  
21 the CPUC's long-term procurement order instituting  
22 rulemaking. There's a lot that's going to be  
23 discussed in that rulemaking. We're hoping that  
24 the most important aspect will be resource  
25 adequacy. In a recent notice issued by the CPUC

1       they've, they've split the resource adequacy out  
2       separate from all the other OIR issues. We  
3       support that. We think that's heading in the  
4       right direction, and we sense that the PUC is  
5       going to finish up on resource adequacy.

6               We're also hopeful that the Western  
7       Power Trading Forum's petition to modify the  
8       January decision deadline of 2008, to move it up  
9       to May 2006, is going to, is going to get  
10      implemented, either in the December final  
11      decision, or hopefully sooner. We've, we've heard  
12      back that, at least initially, they're thinking  
13      that maybe that can get answered in December.

14             We believe it needs to be answered now.  
15      This is kind of -- Commissioner Geesman, you and I  
16      could be the, the now gentlemen in this debate, I  
17      think, so --

18             CHAIRPERSON GEESMAN: I had heard that  
19      they were trying to, to get that in front of their  
20      commission for decision in October. I may be  
21      mistaken in that, but I thought that they had  
22      severed that from the larger procurement decision  
23      and were, were hopeful of having it teed up for a  
24      decision by the full commission in October.

25             MR. CARLSON: Okay. I was not aware of

1       that. I appreciate that. So that's the first  
2       one.

3               You've heard me say resource adequacy so  
4       much, and you've heard me say market design 2002  
5       so much. I would like to propose that, that we  
6       pick up a new acronym and that we see it  
7       throughout the aging power plant study when it's  
8       making reference to related proceedings, and that  
9       is RA-slash-MD02. As I mentioned earlier, we're  
10      of the opinion, as are others, that MD02 is  
11      problematic in the absence of resource adequacy.  
12      And I would --

13             CHAIRPERSON GEESMAN: Yeah, but you, you  
14      sound like you just skipped over procurement. It  
15      sounds like somebody that doesn't have any  
16      permitted but unconstructed power plants looking  
17      to get financing.

18             MR. CARLSON: Well, until there's a  
19      resource adequacy requirement we're going to have  
20      to come up with some short-term reliability  
21      contract fixes. The procurement proceeding is, is  
22      really long-term in nature. So is resource  
23      adequacy, but there's certain elements of both  
24      where we believe we can take action now.

25             In the procurement proceeding, I guess

1 the most important tie-in to resource adequacy,  
2 from our perspective, is that procurement has to  
3 be competitive. It cannot favor any one company  
4 against the other, except with respect to the best  
5 proposal economically.

6 CHAIRPERSON GEESMAN: The Governor has  
7 used the word "transparent" every time he has said  
8 competitive.

9 MR. CARLSON: And we would support that,  
10 as well. And transparent, that would take me into  
11 the Silicon Valley manufacturing groups' straw  
12 proposal for resource adequacy. In that proposal  
13 it's very transparent. In fact, it's so  
14 transparent that if we had that process  
15 implemented now, it would make the work of the  
16 Energy Commission much simpler. Matt Trask and  
17 his team could just pull off of some publicly  
18 available website the value of capacity for 2004,  
19 2005, or whatever the forward period is going to  
20 be for the pricing.

21 The SVMG straw proposal aims at  
22 implementing such a process. It's not a study.  
23 The long-term procurement OIR will be the  
24 culmination of the study. In fact, the aging  
25 power plant study that the Energy Commission is

1       doing, there will be a report.  There won't  
2       necessarily be a process.  Resource adequacy, in  
3       our opinion, is a process.  Having adequate  
4       resources with a deliverability standard applied  
5       is a process.  There are studies that support it.  
6       But it's not a study, a report, and a decision.

7               So I touched on the CPUC resource  
8       adequacy workshop report, the long-term  
9       procurement OIR --

10              CHAIRPERSON GEESMAN:  You haven't said  
11      anything about locational pricing.

12              MR. CARLSON:  Reliant Energy supports  
13      locational marginal pricing in spot markets.  In  
14      fact, several facets of, of what we'd like to see  
15      in RA-slash-MD02, is locational marginal pricing  
16      that includes local market power mitigation that  
17      not only assures that a single supplier cannot  
18      exercise market power, but that a price signal  
19      will come from that locational market power  
20      mitigation.  It'll be transparent, and that price  
21      signal will be sufficient to encourage investment.  
22      And we recognize that the debate nationally, as  
23      well as here in the state of California, has not  
24      yet resulted in a proposal that everyone can agree  
25      to.

1           But I think the Federal Energy  
2       Regulatory Commission has recently ruled in a PGAM  
3       case, that it's got to lean at least in the  
4       direction of sending a signal that will encourage  
5       investment, or create that incentive. It can't be  
6       cost based or less, or else you limit the number  
7       of alternatives to simply transmission, and  
8       transmission, as this Commission is well aware,  
9       transmission's not always a feasible solution to a  
10      problem.

11           I hope I've answered your question.

12           CHAIRPERSON GEESMAN: I think you have.

13           MR. CARLSON: Again, I'll just lay it  
14      out there. Amendment 60, that's a regulatory  
15      proceeding. We've already discussed that. I've  
16      got my assignment, I believe, at least from you,  
17      Commissioner Geesman, if not from the Commission  
18      in general, to see if we can move this thing along  
19      and turn this into something that happens now, as  
20      opposed to a multi-year stakeholder process where  
21      all we do is meet and eat doughnuts.

22           Yeah, it's a new day. It's a new day.  
23      We cannot, we cannot suffer another failure. It  
24      will, the next time something happens there won't  
25      be any blame to go around. There won't need to be

1 any blame going around. It'll be devastating.  
2 Devastating to the economy of the state of  
3 California, devastating to the energy industry,  
4 and it'll probably ripple beyond the electric  
5 industry into other industries. So failure is not  
6 an option in this regard, from our view.

7 CHAIRPERSON GEESMAN: Glad to hear that.

8 MR. CARLSON: So within amendment 60, I  
9 pointed to the California Independent Energy  
10 Producers Association's proposal contained in its  
11 comments to the CALISO's filed amendment 60 at the  
12 Federal Energy Regulatory Commission. One thing  
13 I'd like to add to my comments previously is that  
14 Reliant Energy is not a member of the California  
15 IEPA. So I'm not here as a member of IEPA, waving  
16 that flag. I'm here as a participant in this  
17 market for now that generates electric power,  
18 hoping that there's going to be a competitive  
19 transparent resource adequacy process and not just  
20 more studies, not just more stakeholder processes,  
21 and the way we've done it in the past, as you  
22 referred to it, Commissioner Geesman.

23 We want to see short-term reliability  
24 contracts implemented, and we want to see it  
25 handled in a way much like the Silicon Valley

1 Manufacturing Group approached the problem of  
2 resource adequacy, and that is to get everybody  
3 together, as you've recommended, that I'm taking  
4 away as my assignment, and to see if we can  
5 understand where we really do stand here with  
6 respect to summer 2004 reliability, and see if we  
7 can really keep that as our focus, and see if we  
8 can get something done now.

9 And I'd love to be able to sit here in  
10 front of you in a couple of weeks -- not a couple  
11 of months, in a couple of weeks -- and take you  
12 through a standard form short-term reliability  
13 contract and have at least a majority of the LSEs  
14 on board with it, if not all of the LSEs on board  
15 with it, recognizing that what we're trying to  
16 solve here is reliability. Grid reliability.

17 Finally, I'd like to talk about a  
18 regulatory proceeding related to core/non-core  
19 market design, but there isn't one. And in our  
20 opinion, I'm not so sure we need a regulatory  
21 proceeding, but we may need some new legislation.  
22 One thing is for sure. However it gets done, we  
23 need retail choice if for no other reason than  
24 that a market only works with many buyers and many  
25 sellers to the benefit of the ultimate customer.

1       There's markets in other parts of the United  
2       States that have proven that fact. I was going to  
3       say it's a theory. It's a fact. In fact, I think  
4       it's part of the law of economics to have many  
5       buyers and many sellers, to result in a  
6       contestable or competitive market.

7               Without, without a non-core, the number  
8       of customers, or the number of buyers is limited.  
9       And without competitive procurement for the core,  
10      in our opinion, by way of our experience, by way  
11      of our observations, the core is not assured of  
12      least cost supply.

13              So we would, we would like to see the  
14      aging power plant study point to core/non-core,  
15      and the importance for some type of regulatory  
16      proceeding, or, in fact, better yet, we'd like to  
17      see the study point to the need for legislation.

18              CHAIRPERSON GEESMAN; Now, we did that  
19      in our November 2003 integrated energy policy  
20      report, and I think the Legislature's actually  
21      going to resolve this issue in August. I think  
22      well before the aging power plant study is adopted  
23      by, by our Commission, I think the issue will have  
24      been taken up by the Legislature. I wouldn't, I  
25      wouldn't dare to, to predict the outcome, but I

1 think that it's, it's squarely in front of the  
2 Legislature right now, it's received a  
3 considerable amount of attention, and I think that  
4 they will vote it up or down in August.

5 MR. CARLSON: Right. See if I can  
6 characterize it this way. We would like to see a  
7 core/non-core that is more than a release of a  
8 limited number of captive customers over a finite  
9 period of time. We believe that in this  
10 integrated fashion of making resource adequacy and  
11 the market design all work together in taking into  
12 account not only new resources, but existing  
13 resources. You have to wind up with a system  
14 where there's no new stranded costs, for one. And  
15 the only way to really accomplish that, the only  
16 way that we've seen to this point, is, is the SDMG  
17 straw proposal for resource adequacy where you tag  
18 the capacity, and the LSE's actual metered demand  
19 is the basis for the resource adequacy obligation.

20 Unlike the, the methods back in the  
21 east, where it's all done on a forecasted load  
22 basis and a forecasted obligation basis, the SDMG  
23 has proposed that the obligation is based on  
24 metered demand. And in this way capacity will  
25 follow the load. Not just new capacity, but new

1 as well as existing capacity. And there's,  
2 there's no need for there to be any new stranded  
3 cost in that regard. There is no need to put up a  
4 barrier for incremental non-core customers.  
5 There's no reason that the procurement for core  
6 customers should be anything less than  
7 competitive, and, in the Governor's words,  
8 transparent.

9 So with that, I'll release the mic. And  
10 thank you again for listening to me. Thank you.

11 CHAIRPERSON GEESMAN: Thank you, Trent.

12 MR. LOSCOTOFF: Good afternoon. My name  
13 is Kevin Loscutoff, and I'm with Mirant. And  
14 Mirant owns and operates more than 2,000 megawatts  
15 of just RMR generation in the Bay Area. And I  
16 really don't have a prepared presentation or  
17 prepared comments. I think I just wanted to come  
18 up and, and thank you for having this conversation  
19 today and undertaking this committee, because I  
20 think it's probably the most vital discussion that  
21 the state is having at this time.

22 I think the reason I chose right now to  
23 even mention that is that this question kind of  
24 goes to the heart of that, and that there is no  
25 pending or active regulatory or legislative

1 proceedings that deal with this issue. We're very  
2 supportive of core/non-core, we're very supportive  
3 of resource adequacy, but those are long-term, and  
4 they're, and they're not short-term. And the  
5 problems that aging plants like the ones that we  
6 have are that we begin to run into environmental  
7 constraints.

8           These plants require certain capital  
9 expenditures and, and capital maintenance dollars  
10 that, that we aren't guaranteed. And so in  
11 looking in our future, we don't know what to  
12 think. The stability of the market is not there.  
13 And so it's just, it's a difficult time, and we,  
14 and we have to make difficult decisions.

15           Earlier on Mr. Layton talked about two  
16 units of ours in particular, actually three,  
17 Potrero 3 in, in San Francisco, that we've begun  
18 putting an SCR on. We're happy to be, to be doing  
19 that work and, and cleaning up that unit. But we  
20 also have two units in the, in the East Bay, in  
21 Pittsburg in Contra Costa, Contra Costa 6, which  
22 does not have an SCR nor does it have RMR  
23 coverage. The truth is, is in the future we can't  
24 put on an SCR without some sort of RMR contract.  
25 And we don't know that we're going to get that, so

1 retirement is a very likely scenario for that  
2 unit.

3 Also, on Pittsburg 7, unless we do  
4 receive an RMR contract or the unit proves that it  
5 can sustain itself within our NOx bubble, our  
6 business plan shows that that unit will retire at  
7 the end of this year.

8 CHAIRPERSON GEESMAN: Does it currently  
9 have an RMR contract?

10 MR. LOSCOTOFF: It currently has an RMR  
11 contract.

12 So we have put incremental NOx controls  
13 on, on both those East Bay units, and we'll be  
14 testing them throughout the summer. But the  
15 future of those is, is fairly dim, and that's  
16 1,000 megawatts in the East Bay.

17 CHAIRPERSON GEESMAN: How much did the  
18 Contra Costa unit operate last year?

19 MR. LOSCOTOFF: That, I don't know.  
20 That, I don't know. It was under RMR last year.

21 CHAIRPERSON GEESMAN: Oh, it was.

22 MR. LOSCOTOFF: It was dropped this  
23 year.

24 CHAIRPERSON GEESMAN: Okay. I didn't  
25 realize that.

1 MR. LOSCOTOFF: It was dropped this  
2 year, yes.

3 So those are, those are realities that,  
4 that we have to face going forward, and it's just  
5 very difficult for us. I, I think one of the main  
6 points that we'd like to see happen is a  
7 discussion, a true discussion on capacity markets  
8 where the power producers can realize that value  
9 that isn't realized right now. And, and that's,  
10 that discussion isn't out there quite, quite yet.  
11 We'd like to see that.

12 We'd also like to see longer term RMR  
13 contracts. The year-by-year doesn't give us the  
14 stability that, that we need. And so in the case  
15 of Pittsburgh 7, it's a 680 megawatt unit, a three  
16 or five year RMR contract would be essential for  
17 us to upgrade it to where it really needs to be  
18 environmentally sound. And, and a similar longer  
19 term RMR contract for, for Contra Costa 6. And  
20 those are necessary megawatts for the grid.

21 CHAIRPERSON GEESMAN: And you say, you  
22 say that focused on the SCR retrofits.

23 MR. LOSCOTOFF: Uh-huh.

24 CHAIRPERSON GEESMAN: What other capital  
25 improvements are you inhibited from making for,

1 for lack of a longer than one year RMR contract?

2 MR. LOSCOTOFF: That I, I couldn't  
3 answer specifically. I think I would have to say  
4 that generally most capital expenditures would be  
5 difficult to, to prove worthwhile to our creditors  
6 in this market.

7 CHAIRPERSON GEESMAN: But you've  
8 recovered some of those capital expenditures under  
9 your, your one year RMR contracts, have you not?

10 MR. LOSCOTOFF: Oh, for, for Pittsburgh  
11 7, correct. Yes. Yeah. And, and we have put in  
12 incremental NOx controls so that that unit can run  
13 this, this year. But, but without knowing whether  
14 or not it's going to be RMR'd next year --

15 CHAIRPERSON GEESMAN: Yeah.

16 MR. LOSCOTOFF: -- we can't put in  
17 those, you know, those significant dollars.

18 CHAIRPERSON GEESMAN: And where are you  
19 on your NPDES permit?

20 MR. LOSCOTOFF: Enough to --

21 CHAIRPERSON GEESMAN: Are you, are you  
22 at the point of doing another study for, for the  
23 following five years, or did you just do one in  
24 the last couple of years? When did the 316(a) and  
25 (b) requirements kick in for you?

1 MR. LOSCOTOFF: That, that, I don't  
2 know.

3 CHAIRPERSON GEESMAN: Okay.

4 MR. LOSCOTOFF: That, I don't know.

5 And I just wanted to come up here to  
6 kind of talk about those things. We're going to,  
7 we're going to file some written comments to you  
8 after this hearing, so --

9 CHAIRPERSON GEESMAN: Good. That would  
10 be helpful.

11 MR. LOSCOTOFF: -- I'll try to answer  
12 those, that question, and anything else that you'd  
13 like specifically.

14 CHAIRPERSON GEESMAN: Great. Great.

15 MR. LOSCOTOFF: But those are my main  
16 points, so.

17 CHAIRPERSON GEESMAN: Well, thank you.

18 MR. LOSCOTOFF: Thank you again.

19 MR. TRASK: Any other questions or  
20 comments from the audience?

21 Winding down here. The last question  
22 under this panel is would the development of any  
23 power plant that is permitted but not yet  
24 operational affect the RMR status of the, of any  
25 of the study list units during the timeframe.

1       There we'd be looking at Otay Mesa, Palomar,  
2       Metcalf, or perhaps any others.

3               Any comments?

4               CHAIRPERSON GEESMAN: I presume we have  
5       the -- I don't know what the number is, Contra  
6       Costa 8? But the Mirant plant that we permitted  
7       several years ago that stopped in mid-  
8       construction. I presume that that would have some  
9       potential impact on the Pittsburg 7 RMR project.

10              MR. MICSA: That, that's not getting  
11       built, as far as we know. The, the ones we're  
12       talking about here have probably a higher  
13       potential of getting built than Contra Costa 8.

14              CHAIRPERSON GEESMAN: Okay.

15              MR. MICSA: Just, just one comment. You  
16       know that's the first time I heard about Pittsburg  
17       7 may, may retire. We, we haven't got that  
18       official from, from Mirant yet.

19              One comment that I have here is that  
20       under the RMR contract, the owner of the equipment  
21       is supposed to be keeping it up to complying with  
22       all laws and regulations, including NOx emissions  
23       and everything, and we haven't received requests  
24       from Mirant yet of the upgrades and the money they  
25       need in order to put the SCRs on. We, we did

1 receive that for Potrero 3, Potrero 3, and we have  
2 approved that. We haven't received anything like  
3 that from them regarding Pittsburgh 7. They can't  
4 submit one for 6, because it's not, it's not RMR  
5 anymore.

6 CHAIRPERSON GEESMAN: Now, tell me about  
7 the Potrero SCR retrofit. You approved the, the  
8 full cost of the retrofit under --

9 MR. MICSA: Yes, we, we have, we have  
10 approved the capital cost of installing SCRs, and  
11 I think the recovering period, it's, I don't know,  
12 something like five or ten years, or something  
13 like that. But there is a, there is a stipulation  
14 in there that if, if the unit is not needed for  
15 reliability anymore, and they completely shut down  
16 the plant, then the ratepayers will pay for that  
17 full amount.

18 If, if we don't need the unit, let's say  
19 in two years we don't need the unit for  
20 reliability anymore, and they continue to run the  
21 unit in the markets, then we only made the two-  
22 year payments, and, and then the ratepayers are  
23 off the hook. But if they decide in two years  
24 that, okay, it's not economic to run the plant  
25 anymore and we don't need it for reliability, and

1 they completely shut it down, then the ratepayers  
2 are on the hook for the whole cost of the SCR  
3 retrofit. But they haven't filed anything for  
4 Pittsburgh 7 with us.

5 CHAIRPERSON GEESMAN: And was there any  
6 special consideration that went into the Potrero  
7 plant in terms of the likelihood of it being an  
8 RMR plant for an extended period of time, or would  
9 you apply the same standard to any current RMR  
10 project that, that came to you with a request for  
11 that magnitude of capital improvement?

12 MR. MICSA: Well, we do, we do look, as  
13 we all know, RMRs are for one year at a time, and  
14 we just, we just cannot operate the system for a  
15 single contingency without Potrero 3 in, in 2005,  
16 therefore we had to retrofit it for 2005.

17 CHAIRPERSON GEESMAN: Okay.

18 MR. MICSA: We may, we looked at 2006  
19 and beyond, and under some scenario they're  
20 needed, under some other, you know, scenario they  
21 may not be needed. If, if all the transmission  
22 projects and all the new peakers from San  
23 Francisco are coming on, they, they may not be  
24 needed. But it's just, it's impossible to  
25 maintain reliability in San Francisco for single

1 contingency without that unit in 2005. And that  
2 was the main driver.

3 CHAIRPERSON GEESMAN: Okay.

4 MR. OSTERHOLT: Mark Osterholt, with  
5 Mirant. And I just want to make a clarification  
6 regarding Pittsburg 7.

7 As Kevin stated that we have, we have  
8 done incremental NOx upgrades on that, that unit,  
9 and we will be testing it this summer to see just  
10 what, what load we can reach on the unit. And I  
11 don't know if you're, I know Catalin's familiar  
12 with the NOx bubble in the Bay Area. We will be  
13 able to fit that, that unit in, you know, based  
14 on --

15 MR. MICSA: We will be running some of  
16 the good units more.

17 MR. OSTERHOLT: -- if there are SCR  
18 units running. We're just not sure yet to what,  
19 to what extent we'll, we'll be able to fit in all  
20 the megawatts.

21 So his, his comment related to  
22 retirement of that unit in '05. That would be  
23 absent an RMR agreement. That unit would most  
24 likely be retired in '05.

25 MR. MICSA: Okay. But you will be

1       complying with the, all the NOx regulations in  
2       '05?

3               MR. OSTERHOLT:  We are not certain.  
4       Well, yes, we will be complying with NOx  
5       regulations, but we're not certain what megawatt  
6       load we'll get out of that unit.

7               MR. MICSA:  I guess we'll wait and see.

8               MR. TRASK:  Any other comments?

9               MR. MICSA:  Well, related to your, to  
10      your last questions there, we, as I said before,  
11      we only do RMR studies one year at a time, so, for  
12      example, next year Metcalf has been considered  
13      online in our RMR studies, because they've got to  
14      make the June 1st of next year.  The other units,  
15      we haven't looked at them, but from, from the  
16      interconnection policy that we have, and when we  
17      looked at the units, you know, it sounds -- well,  
18      Palomar currently goes to the load.  Otay Mesa  
19      doesn't quite go to the load, that's why San Diego  
20      proposed that they sign Otay Mesa, and they need  
21      two transmission projects to be approved with  
22      that, otherwise they're not, it's not the same  
23      product from -- basically Otay Mesa can compete  
24      for local reliability with the old units, as well.

25              So there, there is a possibility there

1       that if both Palomar and Otay Mesa come along,  
2       there's some units in San Diego may not be needed  
3       for San Diego local reliability. Palomar itself  
4       probably won't, won't get rid of a whole power  
5       plant, more like two or 300 megawatts worth of  
6       maybe a few units, two or three units. But  
7       together, Palomar and Otay Mesa will probably get  
8       rid of one of the power plants completely, and  
9       maybe a little bit of the other one.

10               MR. TRASK: Is that with or without any  
11       transmission upgrade?

12               MR. MICSA: Otay Mesa has to come with  
13       the transmission upgrades; otherwise it won't  
14       displace anything.

15               CHAIRPERSON GEESMAN: And which  
16       transmission upgrades are you referring to?

17               MR. MICSA: Referring to two brand-new  
18       230 kV lines coming from Miguel towards, towards  
19       San Diego.

20               MR. PETERSON: Sycamore and Old Town.

21               MR. MICSA: Thank you.

22               CHAIRPERSON GEESMAN: Do you happen to  
23       know what the permitting status of those upgrades  
24       is?

25               MR. MICSA: Well, honestly, there was,

1       there was a Catch-22 here.  Probably I could  
2       explain it a little bit.

3               San Diego really wanted to eliminate  
4       some of the high cost, some of the high RMR cost,  
5       so they say they will, they will sign long-term  
6       contracts and have dispatchability rights from  
7       these brand-new units if they can -- displace RMR.  
8       So we told them well, in order for you to displace  
9       RMR you need, for Otay Mesa you need this  
10      transmission upgrades with it.  So that's why they  
11      went and they filed at the PUC we need this  
12      generation and the upgrades.  And the PUC said  
13      we're going to give you the generation, but we've  
14      got to talk more about the transmission lines.  
15      Which, if you only get the generation you're not  
16      going to displace RMR.  That's why San Diego said  
17      no, I'm not going to sign the contract unless you  
18      give me the generation and the lines.

19              So there is a little bit of going back  
20      and forth between San Diego, PUC, us, and probably  
21      Calpine, too, to try to figure out, you know, is  
22      this still the way to go, or, or the PUC has other  
23      ideas.

24              CHAIRPERSON GEESMAN:  And I believe that  
25      the current plan is for Otay Mesa to come on in --

1 MR. MICSA: 2007, I believe. And the  
2 upgrades will come in 2008. We can probably  
3 squeeze them by for one year.

4 CHAIRPERSON GEESMAN: Okay.

5 MR. MICSA: Palomar I think is '06,  
6 something like that.

7 CHAIRPERSON GEESMAN: Palomar I think is  
8 '06. I had thought that Otay Mesa had been rolled  
9 back to '98, but I may be mistaken in that.

10 MR. MICSA: It --

11 MR. VIDAVER: San Diego entered and it  
12 proposes to --

13 MR. TRASK: Would you turn your mic on,  
14 please.

15 MR. VIDAVER: San Diego entered,  
16 proposes to enter into a PPA as of 1/1/08, in  
17 response to which Calpine has said we could be  
18 online by the middle of '07, if that PPA were  
19 signed.

20 CHAIRPERSON GEESMAN: I'm sorry, that's  
21 right.

22 MR. TRASK: Any other comments on the  
23 policies, plans and projects that could affect RMR  
24 status?

25 MR. MICSA: There, there are that --

1 just FYI, CALISO has not approved, but we are  
2 aware that there may be other projects in the  
3 greater Bay Area that may eliminate one or two  
4 units in the Bay Area, as well. So, just, just  
5 FYI.

6 CHAIRPERSON GEESMAN: Transmission  
7 projects?

8 MR. MICSA: Transmission projects.

9 CHAIRPERSON GEESMAN: Are you aware of  
10 any generation problem -- projects in the Bay Area  
11 that would have a similar impact?

12 MR. MICSA: Well, depending on -- see,  
13 the way when, when we do all the RMR technical  
14 analysis every unit has its own effectiveness  
15 factor relative to the worst problems. And for  
16 the worst problems we see right now for the  
17 greater Bay Area, the old units actually have a  
18 high effectiveness factor, so even though their  
19 cost may be higher their effectiveness factor is  
20 higher, so they, they may still come and talk  
21 economically, rather than bring a unit who is less  
22 effective.

23 But if, if some of the main constraints  
24 are fixed, like some of the transmission projects  
25 are coming through, that, that will change. We'll

1 go from this worst contingency to another one.  
2 All effectiveness factor may change, and it may  
3 end up that, you know, even Metcalf may substitute  
4 for some of the old units in the Bay Area, as  
5 well.

6 MR. TRASK: Our last panel was on the  
7 reliability effects of plant retirements.

8 I'll go ahead and read the first  
9 question, then. Would the retirement of any one  
10 non-RMR unit or group of units create a local or  
11 regional reliability problem in any geographical  
12 region in California. What method or tools are  
13 available for the analysis of such problems during  
14 the timeframe of the APPS.

15 I'd especially like to hear maybe a  
16 little bit from IEP on this one, since they made  
17 the interesting comment that, what was it, 75  
18 percent of the units in, in Los Angeles are for  
19 local reliability, for supplying local  
20 reliability.

21 MS. KAPLAN: I'm sure Trent can talk a  
22 little bit about this, as well. I guess, you  
23 know, from our perspective, it's been somewhat  
24 confusing in that if these units aren't needed for  
25 reliability, if they don't have RMR contracts,

1       they've been deemed to be not needed for  
2       reliability, and yet there's a chronic problem  
3       that exists in souther California in which it's  
4       not just a, you know, a fire, or a transmission  
5       line goes out, and then they, you know, things  
6       that you can't predict. And then these are, these  
7       are units that are online every day, every hour,  
8       every month, you know, for the last 18 months.

9               So it's not, you know, that is a chronic  
10       problem. And so I guess, you know, that when we  
11       look at it we say okay, if, if the ISO gives these  
12       units RMR contracts then they're being, then  
13       they're deemed to be needed for reliability. If  
14       they're -- don't give them RMR contracts, then I  
15       guess they're not needed for reliability.

16              So I suppose that would be a question to  
17       the ISO, perhaps more apt than myself. But you'd  
18       need to make sure that when we phrase the question  
19       it's in two different categories. One would be  
20       predictable scenarios, the other one would be  
21       unpredictable scenarios. And I'm not trying to  
22       articulate that an unpredictable scenario such as  
23       the southern California fires or a transmission  
24       line going out, or something like that, that you  
25       would sign up RMRs for every single one of those,

1       you know, contingencies that might or might not  
2       happen. I'm talking about chronic problems that  
3       exist.

4               MR. TRASK: Right. We, we somewhat  
5       struggled with that issue, as well. We've seen,  
6       for instance, physical islanding of service  
7       territories during unusual events, and, of course,  
8       if you're a generator within that island you're  
9       essential to that reliability. We, we haven't  
10      really been able to get much value out of looking  
11      at those unusual events, because they are so  
12      unpredictable and because they don't act the same  
13      way twice.

14             MS. KAPLAN: Right, right.

15             MR. MICSA: I guess I would, I would add  
16      that they're, they're definitely needed for system  
17      reliability. Now, there is another question  
18      that's, you know, how do we go about making sure  
19      they are there. You know. Should we, should we  
20      go and sign them up for all system reliability  
21      problems that we have, or should we take a risk  
22      that some of them may not be there.

23             It's, it's something hard to do, and we  
24      will have to put it up in front of the, the board,  
25      our board and the stakeholders, and, and try to

1       come up with some kind of a criteria to, to  
2       determine at what point do you, do you make sure  
3       that they are there, other than relying on the  
4       markets to provide them.

5               CHAIRPERSON GEESMAN: Yeah. I guess I  
6       have a concern, in a general or abstract way,  
7       that's not plant specific. But it's hard for me  
8       to see anybody making any money if they're only  
9       operating 20 to 25 percent of the time. And I, I  
10      have a big picture apprehension that if we keep a  
11      bunch of plants operating at that low level, we'll  
12      be able to, to keep the entire industry on life  
13      support indefinitely, and none of the plants will  
14      ever rise out of the particular problematic status  
15      that they presently have.

16             And I, I think I'm getting a better  
17      sense as to how to evaluate that against local  
18      reliability concerns. It's a big question mark  
19      in, in my mind when you throw up the concept of  
20      system reliability. Do we really want to have a  
21      large number of, of what in other industries would  
22      be characterized as zombie plants, operating on a  
23      allegedly cost recovery basis, but really only  
24      able to operate 20 to 25 percent of the time, and  
25      bring down the revenue opportunities for everybody

1       else.

2               Japan has had this problem with, with  
3       too many zombie banks. We may have a similar  
4       problem, at least from a system reliability  
5       perspective, with too many zombie plants. And I  
6       don't, I don't have a clear answer, I don't have a  
7       clear way of thinking of it, but, but I will tell  
8       you, it raises a concern in my mind that  
9       perpetuating a plant configuration that, that only  
10      operates 20 to 25 percent of the time is not a  
11      long run solution.

12             MR. MICSA: I guess it's, it's probably  
13      just a matter of fact that the units in that area  
14      are more expensive than what's outside in the tie,  
15      so people prefer to bring a lot of energy on the  
16      ties. But you can only import so much, and once  
17      you're max'd out then your load keeps, keeps going  
18      up in the summer peak time periods. You have to  
19      use the units inside, and they're, they're keep  
20      cycling, they're keep cycling, and they're only  
21      used, like you, you know, you just mentioned, 25,  
22      30 percent of the time.

23             But they are needed, and that, that 25,  
24      30 percent of the time, it represents 7,000  
25      megawatts of, you know, as the graph said, it's up

1 close to 7,000 megawatts.

2 CHAIRPERSON GEESMAN: I think that's  
3 only true as long as you hold constant the  
4 assumption that your capacity on the ties is  
5 limited. And I would suggest that it's probably a  
6 better societal investment to expand that capacity  
7 on the ties than to, to shovel life support  
8 payments to a bunch of plants that will never  
9 operate more than, than 20 to 25 percent of the  
10 time.

11 MR. MICSA: And I completely agree with  
12 you, and that's why the -- adequacy process is  
13 supposed to come up with, with a response like  
14 that, because you really have to look, you know,  
15 these transmission projects we're talking about,  
16 there are 200 mile of 500 kV lines. They cannot  
17 be built in less than five years. You need five  
18 to eight year, sometimes maybe even more to get,  
19 you know, California PUC and maybe Arizona PUC,  
20 and a lot of other utilities -- commissions, to  
21 approve something like that and get it built.

22 And, and that's, so you have to look at  
23 the economics of, you know, how much really costs  
24 the generation outside and how much the  
25 transmission project cost, versus, you know,

1 signing the units inside. But for, for the short  
2 term, there is no alternative. We can't build 500  
3 kV lines in --

4 CHAIRPERSON GEESMAN: Yeah, I, I don't  
5 disagree on the short term. I guess my  
6 frustration is that in the, the slightly longer  
7 than short term, and I've been here almost two  
8 years, which to me seems like long term, I haven't  
9 encountered anybody, outside a handful of civil  
10 servants at the PUC, that disagree with me. And  
11 yet I have a hard time seeing how we've made  
12 appreciable progress in expanding our intertie  
13 capacity. And I think it, it remains a morass  
14 that the state has not yet effectively dealt with.

15 And in the meantime, we end up incurring  
16 congestion costs or continuing to shovel, or feel  
17 the need to shovel life support payments to plants  
18 that over the long run are either going to need to  
19 be substantially redeveloped into new technology,  
20 or which should simply be allowed to, to pass away  
21 quietly into the night. But we seem to have some  
22 institutional logjams that prevent that from  
23 happening.

24 Sorry for the sermon. Matt --

25 MR. TRASK: Preaching to the choir.

1 MS. KAPLAN: We support that, yeah.

2 MR. TRASK: We, too.

3 Further comments on that?

4 MS. KAPLAN: I would just, I would just  
5 suggest that, you know, perhaps on the, if you're  
6 talking about, you know, short term and then maybe  
7 getting to what you'd like to see long term, short  
8 term-wise, it would really help to establish these  
9 local deliverability standards. Because that'll  
10 help define, you know, what upgrades we need on  
11 the interties, what upgrades we need intrastate.  
12 I mean, the intrazonal costs now are more  
13 expensive than the interzonal costs for  
14 congestion. That's crazy.

15 CHAIRPERSON GEESMAN: How difficult a  
16 definitional problem do you think it's going to be  
17 to, to establish local deliverability standards  
18 in, in the procurement process?

19 MS. KAPLAN: Well, I would suggest that  
20 it has to be done at the ISO. Not, not in the  
21 procurement process, to begin with.

22 CHAIRPERSON GEESMAN: I think that's an  
23 answer to my question.

24 MS. KAPLAN: So if you do it at the ISO,  
25 it can be done fast.

1           MR. MICSA: I think we already have a  
2           proposal in front of the PUC.

3           CHAIRPERSON GEESMAN: And I think Katie  
4           just answered the question a little differently  
5           than that, and probably --

6           MS. KAPLAN: Yeah. I forgot to ask  
7           permission to be frank, like Trent did, but -- we  
8           suppose their proposal, by the way.

9           CHAIRPERSON GEESMAN: We'll take note of  
10          it.

11          MS. KAPLAN: It just has to line up, you  
12          know. You know, it has to line up with what  
13          they're asking for for local market power  
14          mitigation, it has to line up with what we're  
15          doing for, you know, procurement, it has to line  
16          up with must-offer, and it has to line up with  
17          RMR. Those pieces have not been connected.

18          CHAIRPERSON GEESMAN: I understand.

19          MR. TRASK: Our remaining two questions  
20          are, are very related to the first question. The  
21          second question, essentially, what effect does the  
22          generation from aging plants in southern  
23          California have on the congestion of transmission  
24          interties used to import bulk power into the  
25          region. Would the retirement of aging units

1       affect the ability to control congestion on these  
2       or other interties.

3               Fairly similar to the first question.  
4       Catalin, any response?

5               MR. MICSА: Well, definitely. Okay, and  
6       we -- they, they do provide reliability right now.  
7       You know, as I said, maybe 25, 30 percent of the  
8       time most of them, some of them are chronic, but  
9       most of them do provide reliability need during  
10      the summer peak time. So they are, they are  
11      basically, these power plants are, are needed.  
12      It's just that, you know, how, how are we going to  
13      be able to keep them around. That's all I can  
14      think of now.

15              MR. TRASK: That sort of leads into the  
16      last question. What are the viable alternatives  
17      that could be developed in time to substitute for  
18      lost generating capacity caused by retirement of  
19      aging steam boiler units in 2004 through 2008.  
20      Could these units, alternatives supply the  
21      reliability services that the aging boiler units  
22      currently provide, such as black start.

23              MR. MICSА: Well, we, we have, we have  
24      tried to do a few transmission projects. Of  
25      course, keeping the existing generation would be,

1       you know, the most, the most effective to maintain  
2       reliability. We have done a few transmission  
3       projects. We got Path 26 from 3,000 to 3400, and  
4       we are working on getting it to 3700. Southern  
5       California Edison has improved the south of Lugo  
6       from 4400 to 5100 just this year, just about a  
7       month ago.

8               We have also done projects at Miguel to  
9       get more import capability from, from Mexico.  
10      There is also a project going on, a short term  
11      upgrade of SWPL. So we're going to get more  
12      capacity from, from Arizona. There are a few  
13      transmission projects that, that we have  
14      implemented or we are in process of getting  
15      implemented that are short term.

16             Now, there are some other ones that are  
17      long term, which is, you know, like the Devers 2,  
18      maybe a new 500 kV substation. Something like  
19      that. Short term, maybe, I don't know, demand  
20      side, building some new generation, but that will  
21      take two to five years.

22             We just, for this time period to 2008,  
23      there's, there is no way we can build 500 kV  
24      lines. It's just impossible to build them in this  
25      short time period.

1 MS. THOMAS: One, one of the things that  
2 I, I do want to point out, though, is that when we  
3 look at this, we just kind of gave you a stacking  
4 order, keeping the existing generation and then  
5 demand side. And I know that it's the state's  
6 preference to select an energy conservation first  
7 prior to generation and transmission, and that's  
8 the preferred stacking order. It's just that  
9 there always needs to be that consideration that  
10 some of this existing generation provides these  
11 other services that demand side couldn't, voltage  
12 support, black start, as listed here, and so  
13 forth.

14 So when, when considering demand side,  
15 we need to consider that.

16 CHAIRPERSON GEESMAN: Yeah, I think that  
17 the appropriate way to look at that is to, to  
18 disaggregate it into the actual services that are  
19 needed, and to, to make an assessment as to, to  
20 how best to provide those services.

21 MR. SCHOONYAN: Gary Schoonyan, Southern  
22 California Edison. Actually, I want to -- I'm a  
23 little late at the switch, I wanted to talk about  
24 a couple of comments made to the previous  
25 questions.

1           One gets at an observation you were  
2       making, Commissioner, with regards to the ability  
3       to import a bunch of power or shut these plants  
4       down. And that, that's been something that's been  
5       ongoing for a long time within the planning of, of  
6       the various systems. However, one of the things  
7       that, that needs to come into play is this  
8       concept, and it was a concept way back in the mid-  
9       sixties, of rolling inertia.

10           You have to have a certain amount of  
11       generation near the load center at all times, else  
12       you run into the problems and the situations that  
13       precipitated the original New York blackout of  
14       1965. So at one point, when I was doing  
15       operations and in charge of planning and what have  
16       you at Edison, it was kind of like a 60/40 rule.  
17       We had to have at least 40 percent of the  
18       generation being produced within the basin, and  
19       there was limits. And I'm not sure what the ISO's  
20       come up with yet, but, but in response to how much  
21       you can shut, you have to have some of that stuff  
22       available.

23           CHAIRPERSON GEESMAN: It's probably  
24       evolved over time as air conditioning has become a  
25       larger part of your load. Because there is less

1 resistance there.

2 MR. SCHOONYAN: The other comment had to  
3 do with the question to, to IEP. And from our  
4 perspective, and frankly, I have not reviewed the  
5 short-term reliability contract, what have you.  
6 Obviously, we believe something's needed along  
7 those lines. I, I'm not so sure that that's the  
8 right approach. From, from our perspective I  
9 believe it would be better handled in the  
10 procurement process.

11 Presently, within our adopted  
12 procurement plan, we do not have the ability to  
13 value that. That's something that we need to get  
14 changed, we're going to change next time we go  
15 through the procurement process. And, and then  
16 basically have those costs covered via the AB 57  
17 type of framework, and what have you.

18 I am, I am not as optimistic as, as  
19 others that the ISO could get something in place  
20 as quickly as we can through a procurement  
21 process, with approval of the Utilities  
22 Commission, whereby we basically go out as part of  
23 that process and are willing to pay a little bit  
24 more for local reliability.

25 From my perspective, the whole concept

1 of the short term reliability contract, just like  
2 the capacity market, just like RMR and ancillary  
3 services and everything else, and I am not saying  
4 these things aren't needed when I say this, that  
5 every time it just means more money. And it's  
6 more money bundled customers have to pay. Every  
7 time you add a product, it increases the amount  
8 bundled customers have to pay.

9 And I think the best place to really  
10 handle that is probably through the procurement  
11 process, and not an additional contract or  
12 contracts, or market, so-called market mechanisms  
13 to try and handle things that, that should  
14 rightfully be handled in an orderly process in, in  
15 a utility fulfilling its obligation as resource  
16 manager for its portfolio.

17 CHAIRPERSON GEESMAN: And are you  
18 talking about the short term procurement authority  
19 that you already have?

20 MR. SCHOONYAN: We do not have the  
21 capability in the short term procurement. Our,  
22 our adopted procurement plan does not include the  
23 ability to include a local reliability adder, for  
24 lack of better words, in evaluating assessments.  
25 From our perspective, that's something that needs

1 to change. It's something I, frankly, I believe  
2 the Commission would be more than willing to adopt  
3 in going forward, and would be a heck of a lot  
4 more timely than trying to go through the  
5 elongated process of FERC and contracts, and all  
6 the other stuff.

7 CHAIRPERSON GEESMAN: But, but then that  
8 would take the form of an amendment to your  
9 existing short term procurement plan?

10 MR. SCHOONYAN: It would either have to  
11 do that on the short term basis, but what I was  
12 looking at was more the next -- we're going to be  
13 filing our procurement plan pretty quick.

14 CHAIRPERSON GEESMAN: Yeah. That's what  
15 I was afraid of.

16 MR. SCHOONYAN: We, we file them all the  
17 time, every year. But I was also happy to hear,  
18 at least it was my understanding, maybe I had wax  
19 in my ear, that the ISO was considering moving  
20 forward on the Etiwanda 3-4 RMR. I thought that's  
21 what I heard them say this morning.

22 CHAIRPERSON GEESMAN: Yeah, I think I  
23 saw a copy of a letter to that effect that Jim  
24 Detmers signed late last week.

25 MR. SCHOONYAN: Well, that's great. I

1 mean, actually, they're responsible for grid  
2 reliability. That is clearly a grid reliability  
3 concern, short term, and that's probably the best  
4 way to proceed.

5 CHAIRPERSON GEESMAN: But let me, let me  
6 ask you, Gary, because, you know, I think Etiwanda  
7 is probably a perfect case study for any number of  
8 difficulties. You know, Etiwanda put itself out  
9 to bid under, under a settlement agreement last  
10 October, I think. No bidders. Including no  
11 bidders, no bid from, from the Edison Company.  
12 Here six, seven months later, perceptions change,  
13 we, we need Etiwanda. What, what's wrong with  
14 that picture? Is it just a question of, of  
15 imperfect forecasting, or are there, there cost  
16 recovery issues that haven't been adequately  
17 addressed, or --?

18 MR. SCHOONYAN: Well, there are several  
19 things, first of which is our adopted procurement  
20 plan did not provide us, that the Commission  
21 adopted, did not provide us the ability to  
22 participate in a generation initiated RFO. I  
23 mean, we, we couldn't do it. We have since got  
24 approval to, to go forward with those sorts of  
25 things, and will be participating to the extent

1       Etiwanda 3 and 4 is, is not already under contract  
2       and going forward. We will be participating this  
3       October in that.

4               CHAIRPERSON GEESMAN: And what did you  
5       have to do to get that authority, just an advice  
6       letter?

7               MR. SCHOONYAN: I believe it was an  
8       advice letter. I, I'm not 100 percent sure,  
9       Commissioner. But we were precluded from doing  
10      that, given what we, the plan that we were  
11      following. I mean, and frankly, no one ever  
12      envisioned the sort of, of an offering that  
13      Reliant was making, that, that generators would be  
14      offering output through an RFO process.

15              CHAIRPERSON GEESMAN: Yeah, it just, it  
16      just seems to me, and I, I was not in any way a  
17      fan of the state's request to the ISO, I guess now  
18      a year and a half ago, to provide the state with a  
19      year and let the state wrestle with resource  
20      adequacy, suspend your, your efforts to do that  
21      under MD02. I thought that was foolish at the  
22      time, and that, that your board made a poor  
23      decision in agreeing that the state ought to give,  
24      be given a year.

25              But it would seem to me that, that last

1 summer or fall, all of us should've been able to  
2 foresee some prospect that, that the type of  
3 option that Etiwanda was holding should've  
4 generated some bids. I mean, I, I think if, if  
5 you weren't provided adequate authority that  
6 there's something institutionally wrong there, and  
7 I'm not certain, frankly, which, which side of the  
8 table it, it rests on.

9 MR. SCHOONYAN: A couple of other things  
10 that came into play, at least from my, my  
11 perspective, Commissioner, is that there have been  
12 some changes since that October timeframe. One  
13 is, is I don't think -- figured that Etiwanda 3, 4  
14 would be shut down. I, you know, it was kind of a  
15 thing someone would take it up, what have you. I,  
16 I think there was that aspect.

17 There were retirements. There's also  
18 been a, a de-rating, a significant de-rating on  
19 the pacific intertie.

20 CHAIRPERSON GEESMAN: Right.

21 MR. SCHOONYAN: That has had an impact,  
22 because that's a DC facility that drops power in  
23 the heart of our load center. With that in place,  
24 it relieves the, the problems associated with the  
25 south of Lugo.

1 And, you know, that's --

2 CHAIRPERSON GEESMAN: But that's  
3 scheduled maintenance. I mean, it, when was that  
4 announced? I don't, I don't know the answer to  
5 that question, but it's, it's something that it  
6 seems to me that somebody's asleep at the switch  
7 at the state level, that that wasn't a foreseeable  
8 problem. And if, if you lack adequate authority  
9 to participate in the option, I think that's a  
10 problem at the state level, as well. And if you  
11 guys failed to point that out to your appropriate  
12 regulator, I think that's a problem, a problem  
13 within your company.

14 And, you know, at some point the  
15 consequences of us continuing to, to stay behind  
16 the eight ball are pretty severe. I know your  
17 interruptible customers don't like it. I don't  
18 think your other customers would if they end up  
19 being interrupted.

20 MR. SCHOONYAN: And as I mentioned, we  
21 did point it out to the Commission and do have  
22 authority going forward to participate in that  
23 sort of thing. Whether it was as timely as, as  
24 all of us would've liked, that remains to be seen.

25 MS. KAPLAN: I, I would also suggest

1       that at the same time period, you know, the must  
2       offer obligation was in place, and I'm sure the  
3       factor, you know, you talk about disincentives,  
4       why would you contract for it when you can get it,  
5       you know, through the must-offer obligation, and  
6       even more so, spread the cost to PG&E, the  
7       municipals and San Diego, which is how the cost  
8       allocation works for the must-offer obligation.

9               So why would you go enter into a  
10       contract with someone when you can spread the cost  
11       with your neighbors?

12              MR. SCHOONYAN: That was not a part of  
13       any discussion that we had. No, seriously. I  
14       mean --

15              CHAIRPERSON GEESMAN: I understand that.  
16       And she's about to say it didn't need to be a part  
17       of any conversation. That, this has been, it's  
18       been a ball back and forth across the net for  
19       awhile, and I guess I'm less interested in that  
20       history than is there some way in which we can  
21       proceed going forward that provides a little more  
22       assurance.

23              Where are we, Matt?

24              MR. TRASK: Well, that's all the  
25       questions we have, and we've been through all the,

1 the panels, so that's it from staff, unless  
2 anybody else would like to add comments,  
3 questions, concerns.

4 MS. KAPLAN: Thank you very much for the  
5 opportunity to be here today and --

6 CHAIRPERSON GEESMAN: I think this has  
7 been useful. And, and it will produce, I think, a  
8 very good evidentiary record for us, and, you  
9 know, we, we will have some more workshops on this  
10 as the summer progresses. We'll put a report out  
11 there and expect it to trigger a fair amount of  
12 comment. It's an ongoing challenge for us.

13 MR. SCHOONYAN: I have a, a couple of  
14 additional observations real quick. With regards  
15 to the presentation that the staff made, well, one  
16 was a presentation element, the other was a  
17 comment David made on his conjecture on, on why  
18 we, we went with a maximum of three year  
19 arrangements. And the conjecture was that there'd  
20 be more sellers out there in 2007, 2008. And, and  
21 I'm here to say that that was not the reason. The  
22 reason has been and -- is, and has been the  
23 concern over a durable framework going forward.

24 I mean, we, we talk about core/non-core.  
25 I mean, that represents, even the modest proposals

1       that are out there are close to 40 percent of our  
2       load. Very concerned over signing long-term  
3       arrangements whereby huge amounts of our customer  
4       base can basically evaporate.

5               CHAIRPERSON GEESMAN: With no --

6               MR. SCHOONYAN: And, and leaving bundled  
7       service customers --

8               CHAIRPERSON GEESMAN: With no obligation  
9       that goes along with them. No exit fee that would  
10      fully compensate you for that.

11              MR. SCHOONYAN: That's always been a  
12      concern, exit fees. And frankly, I, I think if  
13      you talk to any ESP out there, or community choice  
14      folk, they don't want exit fees either. I don't  
15      think anyone wants to, to deal with the exit fee  
16      issue. You would just as soon try to, to come up  
17      with a, a timely framework going forward, such as  
18      you can transition into whatever market design  
19      that's out there. As opposed to, to facing the  
20      issues of exit fees.

21              Frankly, from what we've seen from exit  
22      fees is that in the end, the smaller bundled  
23      service customers tend to get stuck with a higher  
24      proportion of the cost than will ever be captured  
25      in the exit fee.

1           And so, from our perspective, that's,  
2           that's a way of looking at it. I mean, that was  
3           one of the concerns I know that we have with what  
4           you and President Peavey and, and the Governor put  
5           forth with regards to accelerating the date to  
6           2006, is all at once you're going to be signing up  
7           a lot of long-term commitments. And in essence,  
8           those were long-term commitments. At the same  
9           time, you're talking about once again opening up  
10          the market.

11          And, granted, I think the idea of a  
12          capacity market makes a lot of sense,  
13          Commissioner. We've had discussions with the  
14          Silicon Valley folk, and, and I think some sort of  
15          a capacity market needs to be in place. But I  
16          guess what I've been -- and this isn't an Edison  
17          opinion, this is my opinion -- what I have been  
18          pushing the company for is that to the extent that  
19          we have to sign these contracts sooner without a  
20          durable framework in place, that there's a  
21          provision in those contract that to the extent  
22          that a framework does get in place that creates  
23          the potential for stranded cost, that contract get  
24          downsized, or terms and conditions change such  
25          that our bundled service customers aren't holding

1 the bag.

2 To the extent there's a capacity market  
3 out there, and we heard Trent, from Reliant, what  
4 a great thing this is, if it's such a great thing,  
5 they would be able to market their capacity  
6 through that market without relying upon the host  
7 LSE who has the original contract.

8 So I guess from my perspective, to the  
9 extent that things are accelerated, there ought to  
10 be provisions in there that protect the small  
11 bundled service consumers.

12 CHAIRPERSON GEESMAN: Well, I agree with  
13 consumer protection, as you know. I guess the  
14 problem I have with your description, and it's  
15 something that Commissioner Peavey I think  
16 articulated at the core/non-core en banc, you  
17 create the impression that you would willingly  
18 take us all over a cliff locked into the status  
19 quo market configuration if you don't get the  
20 market redesign as you would specifically like to  
21 see it. And I don't think that's an acceptable  
22 position to have. I think that, that we all need  
23 to figure out a way in which to move forward and  
24 meet the needs of a growing economy and a growing  
25 population.

1           And I do think there are some safeguards  
2     to, to prevent you from, or to protect you from  
3     the exposure you're fearful of. They, they do  
4     require a certain amount of faith in both the  
5     power of the Public Utilities Commission and the  
6     power of the Legislature to enforce exit fees and  
7     to prevent cost shifting. But your company's  
8     proven pretty successful at the PUC and at the  
9     Legislature before, and I think we can probably  
10    work out those protections.

11           But I don't think the status quo is, is  
12    a viable way to go forward. It's cracking now.  
13    You know, we're, we're having events that no one  
14    had anticipated six or eight or nine months ago.  
15    We've got load growth that no one had forecast.  
16    We need to move forward, and I think we very much  
17    need the help of your company to do that.

18           MR. SCHOONYAN: By no means is my  
19    company going to push things over a cliff. And,  
20    and that, that is not the case. I mean, we, we  
21    are, we basically -- frankly, the only regulated  
22    utility in the state that wants to remain a  
23    regulated utility, and not do other things. So  
24    that, that is not the case. It's just that in  
25    moving forward, and we're signing one, three-year

1 type of agreements to get us through this  
2 timeframe.

3 So it's not the case of basically  
4 leading the state over a cliff, by any stretch of  
5 the imagination.

6 CHAIRPERSON GEESMAN: Well, you entered  
7 into a longer agreement than that with respect to  
8 the Mountain View project, so I know that your  
9 vision extends beyond that one to three year  
10 horizon when you feel it needs to. And I, I would  
11 suggest that there are a lot of other areas where  
12 it needs to, and that we could very much benefit  
13 by a more constructive engagement in trying to  
14 address that.

15 MR. SCHOONYAN: We would love if the  
16 generators could come forward with a 30-year  
17 arrangement at the prices of Mountain View.

18 CHAIRPERSON GEESMAN: Several of them  
19 insisted they could.

20 MS. KAPLAN: We'd be happy to.

21 MR. SCHOONYAN: They indicate, I mean,  
22 they indicate it, but when asked on the stand to  
23 do that for PG&E and in the San Diego case, they  
24 were, they basically said the offer's off. It's  
25 not for them.

1           CHAIRPERSON GEESMAN: Well, that's,  
2           that's why the Governor speaks in terms of  
3           transparent and competitive procurement. And  
4           hopefully we'll achieve both of those.

5           I think we've probably thrashed this  
6           around enough. I want to thank everybody for your  
7           participation.

8           (Thereupon, the California Energy  
9           Commission Integrated Energy Policy  
10          Report Committee Workshop on the  
11          Aging Power Plant Study was  
12          concluded at 4:34 p.m.)

## CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter,  
do hereby certify that I am a disinterested person  
herein; that I recorded the foregoing California  
Energy Commission Workshop; that it was thereafter  
transcribed into typewriting.

I further certify that I am not of  
counsel or attorney for any of the parties to  
said workshop, nor in any way interested in the  
outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto  
set my hand this 21st day of June, 2004.

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